



**ECONOMIC FEASIBILITY OF SOLAR PV AND CCGT POWER
GENERATION PLANTS IN THE SPANISH ELECTRICITY
MARKET**

BY

PEDRO ALDECOA VALCARLOS

JUNE 2018

MSC. ELECTRICAL ENERGY SYSTEMS

SCHOOL OF ENGINEERING

CARDIFF UNIVERSITY

APPENDIX 1: Specimen Layout for Declaration/Statements page to be included in Taught Master's Degree Dissertations

CANDIDATE'S IDNUMBER	1810609
CANDIDATE'S SURNAME	Please circle appropriate value Mr / Miss / Ms / Mrs / Rev / Dr / Other please specifyMr.....
CANDIDATE'S FULL FORENAMES	PEDRO ALDECOA VALCARLOS

DECLARATION

This work has not previously been accepted in substance for any degree and is not concurrently submitted in candidature for any degree.

Signed  (candidate) Date ...22/06/2018.....

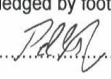
STATEMENT 1

This dissertation is being submitted in partial fulfillment of the requirements for the degree ofMSc.....(insert MA, MSc, MBA, MScD, LLM etc, as appropriate)

Signed  (candidate) Date ...22/06/2018.....

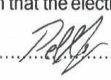
STATEMENT 2

This dissertation is the result of my own independent work/investigation, except where otherwise stated. Other sources are acknowledged by footnotes giving explicit references. A Bibliography is appended.

Signed  (candidate) Date ...22/06/2018.....

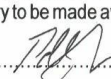
STATEMENT 3 - TO BE COMPLETED WHERE THE SECOND COPY OF THE DISSERTATION IS SUBMITTED IN AN APPROVED ELECTRONIC FORMAT

I confirm that the electronic copy is identical to the bound copy of the dissertation

Signed  (candidate) Date ...22/06/2018.....

STATEMENT 4

I hereby give consent for my dissertation, if accepted, to be available for photocopying and for inter-library loan, and for the title and summary to be made available to outside organisations.

Signed  (candidate) Date ...22/06/2018.....

STATEMENT 5 - BAR ON ACCESS APPROVED

I hereby give consent for my dissertation, if accepted, to be available for photocopying and for inter-library loans **after expiry of a bar on access approved by the Graduate Development Committee.**

Signed  (candidate) Date ...22/06/2018.....

ABSTRACT

The aim of this project is to describe the expected evolution of the Spanish electricity sector in the coming decades, as well as to study the economic feasibility of solar PV and CCGT power generation plants in this context.

First of all, an analysis of the Spanish electricity market has been carried out. The current energy situation has been also studied, both globally and nationally. Given the growing importance of renewable energies in the sector, the legislative development on renewables has been studied, as well as the impact they have generated in the sector and their different financing mechanisms.

Based on the environmental objectives established by the European Union, the general lines of the expected energy transition in the Spanish electricity sector have been defined, estimating the installed capacity of the main generation technologies for the period 2020-2050, as well as their contribution in the generation mix. Likewise, an analysis of the price of electricity in the daily market has been carried out, from which a price prediction model has been developed.

According to the results, the weight of renewables will increase progressively during the next decades, reaching in 2050 an approximate share of 90% in the generation mix. The expected load factor for CCGTs, on the other hand, will increase in the mid-term, whereas in the long-term will be reduced below the current values. The price of electricity, on the other hand, will increase significantly between 2020 and 2030, whereas as of this year will undergo a gradual but steady reduction.

Given the expected relevance of solar PV and CCGT technologies in the future Spanish generation park, the economic feasibility of both technologies has been studied. In the case of the solar PV plant, an analytical model has been developed in MATLAB by which forecasts of the generation of the plant have been made. These results have been validated by the software SOLAR PV, making a comparison between both results. For the analysis of CCGT plant, the price in the adjustment markets has been studied, analysing its relationship with the price in the daily market. According to the results, both projects would be profitable.

However, given the uncertainty inherent to forecasts of the price, alternative forecasts have been considered. Due to substantial differences in the mid-term, the main financial parameters of solar PV and CCGT power generation plants have been calculated again, considering in this case the alternative forecasts of the price. From this second analysis it has been concluded that, whereas the solar PV would not require any additional financing mechanism in order to be profitable, capacity payments would be indispensable in the case of the CCGT plant. It has been also concluded that, in the analysis of the economic feasibility of marginal technologies, such as CCGTs, the average price of the electricity in the markets is not a representative parameter.

ACKNOWLEDGEMENTS

Thanks to Dr Carlos Ugalde and Dr Meysam Qadrdan for giving me the opportunity to carry out a project according to my concerns, as well as for advising me and facilitating the work throughout the realization of the project.

TABLE OF CONTENTS

ABSTRACT	ii
ACKNOWLEDGEMENTS	iii
1.- INTRODUCTION	2
1.1.- Motivation.....	2
1.2.- Objectives.....	2
1.3.- Structure	3
2.- LITERATURE REVIEW	3
2.1.- Description of the Spanish electricity market.....	3
2.1.1.- Introduction.....	3
2.1.2.- Iberian electricity market	4
2.2.- Analysis of the energy sector	12
2.2.1.- Global outlook.....	12
2.2.2.- Spanish energy system	17
2.3.- Theoretical background of solar PV power generation plants	32
2.3.1.- Solar radiation.....	32
2.3.2.- Solar cells.....	35
2.3.3.- Solar generators.....	38
2.3.4.- Inverters	39
3.- FORECASTS OF THE SPANISH ELECTRICITY MARKET	41
3.1.- Electricity generation mix	41
3.1.1.- Forecasts for different technologies.....	41
3.1.2.- Installation of new capacity	44
3.1.3.- Results	49
3.2.- Price of the electricity in the daily market.....	51
3.2.1.- Costs of a power generation plant.....	51
3.2.2.- Analysis of the price in the daily market	53
3.2.3.- Forecasts of the price of the electricity in the daily market.....	68
4.- ECONOMIC ANALYSIS OF SOLAR PV AND CCGT PLANTS.....	83
4.1.- Generation forecasts of a solar PV plant in Spain.....	83
4.1.1.- Location.....	83
4.1.2.- Calculation of the forecasts by MATLAB	84
4.1.3.- Validation with SOLAR PV	91
4.2.- Economic feasibility of solar PV generation plant	94
4.3.- Economic feasibility of CCGT power generation plant	98

4.3.1.- Analysis of the price in the adjustment services market	98
4.3.2.- Financial parameters of the plant.....	102
5.- ECONOMIC ANALYSIS BASED ON DIFFERENT FORECASTS	106
5.1.- Different price of the electricity in the daily market	106
5.1.1.- Economic analysis of solar PV	107
5.1.2.- Economic analysis of CCGT.....	108
5.2.- Different load factor for CCGTs.....	111
6.- CONCLUSIONS	113
7.- REFERENCES	116
8.- APPENDICES	123
8.1.- Legislative development regarding renewable generation	123
8.1.1.- Precedents.....	123
8.1.2.- The special regime.....	123
8.1.3.- Promotion of renewable energies	124
8.1.4.- The problem of the tariff deficit	125
8.1.5.- Current situation	127
8.2.- Financing methods.....	128
8.2.1.- Participation in the spot market	128
8.2.2.- Support mechanisms	129

1.- INTRODUCTION

1.1.- Motivation

The liberalization process of the Spanish electricity market began 20 years ago, and since then the electricity sector has undergone a profound transformation, both at the technological and at the legislative level. Nevertheless, as a result of the economic crisis that occurred in 2008 and specific structural problems of the sector, the energy transition that Spain was undergoing in favour of renewable energies or low-carbon sources has been interrupted until now.

With the expected entry into force, this year, of the new Law on Energy Transition and Climate Change, however, the lines to be followed in the next years will be probably established in order to achieve the environmental objectives agreed with the European Union. In this context, an analysis of the electricity sector as a whole has been wanted to carry out, reviewing its evolution until now, estimating its evolution in the coming decades and focusing in the main technologies that will lead this energy transition.

1.2.- Objectives

The main objectives of this project are, on the one hand, to forecast the evolution of the Spanish electricity sector in the coming decades regarding the generation mix and the price of the electricity in the daily market. On the other, based on these forecasts, it is intended to analyse the economic feasibility of solar PV and CCGT power generation plants, given their importance in the future Spanish generator park. In order to carry out these two analyses, the following objectives have been established:

1. Analyse the functioning of the Spanish electricity market, describing the entities involved, the agents participating in it and the different markets in which it is constituted.
2. Describe the energy transition foreseen for the coming decades at a global level, as well as the trajectory and current situation of the Spanish electricity sector.
3. Estimate the future Spanish generation mix, calculating the installed capacity of each technology and its contribution in the generator park for the period 2020-2050.
4. Analyse the dynamics of the price in the daily market, establishing its determining factors and its relationship with other energy products. Based on this analysis, develop a model for predicting the price of electricity in the daily market for the period 2020-2050.
5. Determine the electricity generated by a solar PV plant in a specific location in Spain, by means of an analytical model developed in MATLAB and, alternatively, by to SOLAR PV software.
6. Analyse the economic feasibility of a solar PV plant with an installed capacity of 50 MW, based on the forecasts carried out previously.
7. Study the dynamics of the price in the adjustment markets and, subsequently, analyse the economic viability of a CCGT plant of 50 MW, based on the forecasts made previously.
8. Analyse the economic feasibility of both plants based on alternative price predictions and make a comparison between the results obtained.

1.3.- Structure

Chapter 2 is a literature review of the essential contents for understanding the calculations carried out in the project. Section 2.1 contains an analysis of the functioning of the Spanish electricity market. Section 2.2, for its part, contains the forecasts made globally for the evolution of the energy sector in the coming decades, as well as an analysis of the past and current situations of the Spanish electricity sector. Section 2.3, finally, contains the theoretical background necessary to calculate the electricity generated by a solar PV plant based on its location.

In Chapter 3, forecasts are carried out on the evolution of the Spanish electricity sector in the period 2020-2050, both with regard to the generation mix (Section 3.1) and the price of the electricity in the daily market (Section 3.2). In Chapter 4, the economic feasibility of solar PV and CCGT power generation plants is studied. Section 4.1 calculates the electricity generated by a solar PV plant in a specific location in Spain. Based on these results, as well as on the forecasts of the price made in Section 3.2, in Section 4.2 the economic feasibility of the solar PV plant is analysed. Section 4.3, lastly, contains the analysis of the economic feasibility of the CCGT power generation plant.

Chapter 5 contains a second economic analysis of the plants. In Section 5.1, alternative forecasts of the price of the electricity are considered. In Section 5.2, conversely, different expected load factors for the CCGT plant are considered. Finally, Chapter 6 contains the main conclusions of the project. As appendices, Chapter 8 includes an analysis of the legislative development in relation to renewable energies in Spain (Section 8.1) and the main mechanisms for financing renewable electricity generation sources (Section 8.2).

2.- LITERATURE REVIEW

2.1.- Description of the Spanish electricity market

2.1.1.- Introduction

The liberalization process in Spanish electricity market began as a result of the entry into force of the Law 54/1997, of November 27, of the Electricity Sector, following the requirements established by the European Union in the Directive 96/92/EC, of December 19, for the attainment of an internal energy market [1] [2].

After its entry into force, activities related to electricity generation and commercialization happened to be exercised under the principle of free competition, settling their economic retribution in the organization of a wholesale market. Transportation and distribution, for their part, were partially liberalized through a generalized third-party access to the grid, being however regulated activities in a regime of natural monopoly. Nevertheless, retribution to the said activities continued to be fixed administratively, based on their operational costs. Vertical disbandment of the activities mentioned was also attempted, segregating activities in a regime of natural monopoly from those which were developed in a regime of free competition [6].

Lastly, the management of the national electric system was entrusted to two commercial and private societies, responsible for economic and technical management, respectively [1].

As a result of the International Agreement related to the Constitution of an Iberian electricity market between the Kingdom of Spain and the Portuguese Republic, made in Santiago de Compostela in October 1, 2004, activities destined to the electric power supply happened to be exercised in a common market for both countries, with the denomination of Iberian Electricity Market, hereinafter referred to as MIBEL. This is defined, in the article I of the said Agreement, as the one formed by the set of organized and non-organized markets in which electric power transactions are carried out. Financial instruments are also traded, which take as references energy-based products [3].

The article IV set the goal of creating an Iberian Market Operator (OMI) for assuming the functions of the operators of both countries. In the meantime, OMI-Portuguese Pole, SGMR (OMIP) would act as the management company of the futures market, and OMI, Spanish Pole, S.A. (OMIE) as the management company of the daily and intraday markets. Nevertheless, in July 1, 2011, a new organizational structure was accepted, under which OMI turned to an entity composed of these two holding companies, with crossed holdings between each other of 10%, and possessing as well each of them the property of 50% in the capital of the management companies of the market [4].

The article X establishes, finally, the supervisory entities of MIBEL in both countries: in Spain, the National Stock Market Commission (CNMV) and the National Energy Commission (CNE) which, as of 2013, was integrated in the National Commission of Markets and Competition (CNMC) [5], and in Portugal, the Regulatory Entity for Energy Services (ERSE) and the Commission of the Securities Markets (CMVM).

Since the entry into force of the Law 54/1997, of November 27, fundamental changes have occurred in the electric sector, such as the high investment in transport and distribution networks, the progressive penetration of renewable technologies or the evolution of the wholesale market in relation to its complexity. Likewise, the accumulation of annual imbalances between income and costs of the electric system caused, in the last decade, the appearance of a structural deficit for whose management the said law proved insufficient [6].

The new Law 24/2013, of July 26, of the Electric Sector, by which the Law 54/1997, of July 27 is repealed, provides a stable regulatory framework which palliate the normative dispersion due to the legislative activity of the last years. Its basic purpose is to establish the regulation of electric sector guaranteeing the electric supply with the necessary levels of quality and at the lowest possible cost, to ensure the economic and financial sustainability of the system and to allow an effective level of competition within the electric sector [6].

2.1.2.- Iberian electricity market

Electric power production market is the one integrated by the set of commercial transactions of purchase and sale of energy and other services related to the supply of electricity. This is structured in a sequence of successive markets: futures markets, daily market, intraday market, non-organized markets and system adjustment services market, understood as such the resolution of restrictions for guarantee of supply and technical restrictions of the system, supplementary services and deviations management [7].

The activities dedicated to the electricity supply are formed by generation, transportation, distribution, energy recharge services, commercialization and intracommunity and international exchanges, as well as the economic and technical management of the electric system [6].

The said activities, for their part, are developed by the following subjects [6]:

- a) *Electric power generators*: have the function of generating electricity, as well as of building, operating and maintaining the production facilities.
- b) *Market Operator*: responsible for the economic management of the system. It is responsible for receiving the sale and acquisition offers of electric power, as well as for the liquidations of the operations carried out in the market [4].
- c) *System Operator*: responsible for technical management of the system, whose main function is to guarantee the continuity and security of electricity supply and the precise coordination of generation and transportation system, through the management of system adjustment services [3].
- d) *Transporters*: have the function of transporting electric power, as well as of building, maintaining and manoeuvring the transportation facilities.
- e) *Distributors*: have the function of distributing electric power, as well as of building, maintaining and operating the distribution facilities devoted to provide the electric power in the consumption points.
- f) *Marketers*: accessing the transportation or distribution networks, they acquire electric power for sale to consumers, other subjects of the system or for conducting international exchanges.
- g) *Consumers*: they acquire energy for their own use. Consumers who acquire energy directly in the production market are called Direct Consumers in Market.
- h) *System load managers*: being consumers, they are enabled for the resale of electric power for energy recharge services.

2.1.2.1.- Future markets

Futures markets include transactions referring to energy blocks with delivery after the day following the contracting, of liquidation both physical and for differences [3]. In the said markets electricity purchase-sale contracts are exchanged, years, months, weeks or days before the physical delivery, with delivery periods longer than 24 hours (weeks, months, trimesters, years, etc.) [12].

Futures markets with sufficient depth and liquidity are essential in risk management and the promotion of competition. On the one hand, fixing forward prices avoids the exposure to the volatility inherent to the daily market, facilitating the risk coverage of both purchasers and sellers of electric power. On the other, being reduced the exposure to risk, they facilitate the entrance of new competitors in the market [12].

According to economic theory, the expected price in the daily market is the opportunity cost of futures contracts, so that the futures market agents effect their offers based on forecasts on the daily market price. The said expectations are reflected in the forward curve, which indicates the prices at which electricity is being exchanged at different time [12].

At the operational level, price in futures markets is determined by the cross between supply and demand, which is articulated according to the particular rules of the different futures markets: organized and non-organized, being constituted the last ones by bilateral contracts and OTC contracts, among others [12].

Organised market

The derivatives market of MIBEL is an organized market in which forward transactions are made on electricity and gas, including futures, options and other operations whose underlying is electricity, gas or energy-based products [13].

According to the International Agreement signed by Spain and Portugal for the creation of MIBEL, the derivatives market is directly subjected to the Portuguese legislation. OMIP is the management entity of the said market, being responsible for the negotiation of the operations carried out therein [14].

OMI Clear, C.C., A.A. (OMIClear), for its part, is the management entity that assumes the functions of the Clearinghouse and Central Counterparty of the positions registered within it. The first one refers to the responsibility for the compensation, risk and guarantees management, determination of required margins and financial liquidation of the positions registered therein. The second one implies acting as a common purchaser in front of the sellers, and as a common seller in front of the purchasers [13].

The negotiations accomplished by OMIP and the compensation process in OMIClear are anonymous. Likewise, all purchase and sale orders are public for participants. With the objective of promoting the existence of liquidity, OMIP closes Market Creator Deals by which the agents adhered to them assume the obligation of quoting purchase and sale prices continuously or at the express request of OMIP [13].

In the derivatives market the agents make public their offers of purchase and sale in the electronic platform managed by OMIP. The transactions for closing positions can be conducted equally through the said platform by a standardized procedure [12]. The negotiation session consists of three consecutive phases [14]:

- a) Opening phase:* initial period of activity of a day of negotiation, during which negotiating members can interact with the negotiating platform solely to remove constant bids from the central order book and create, modify and remove bids from the local order book, without being able to carry out operations.
- b) Negotiating phase:* active period of the session, during which it is allowed the execution of operations, either in continuous market or by auction.
- c) Closing phase:* final period of activity of a day of negotiation, in which negotiating members have the same functionalities as in the opening phase at their disposal.

The contracts offered in this market are standardized, and can adopt the following forms [13]:

- a) Futures contract:* term contract negotiated in the derivatives market, by which the parties are obliged to buy and sell an underlying asset, in standardized quantity and quality, at predetermined date and place, at a price agreed at the present, being subjected to daily liquidation of gain and losses in the negotiation period.

- b) *Forward contract*: unlike futures, forward contracts can be negotiated out of the derivatives market, and they are not subjected to daily liquidation of gain and losses in the negotiation period.
- c) *Swap contract*: term contract negotiated out of the derivatives market and with exclusively financial liquidation, according to which the purchaser agrees to pay a fixed amount for a notional quantity of a certain asset, committing the seller to pay a variable amount for the said notional quantity.
- d) *(Call) Options contract (purchase or sale)*: financial contract, negotiated both inside and outside the derivatives market, according to which the purchaser acquires the right, but not the obligation, of buying the underlying asset, in a predetermined place, in a standardized quantity and quality, in a future date, at a price agreed in the present.

With regard to liquidations, OMIClear is in charge of the daily liquidation of gains and losses (mark-to-market) during the negotiation period, taking into account two prices [14]:

- a) *Fixed price*: reference price of negotiation of futures contracts.
- b) *Variable price*: reference price of spot market, defined on a daily basis.

The daily difference between these two prices constitutes the basis for the daily financial liquidation during the delivery period [14].

Non-organised market

- Over the Counter (OTC) market: it consists of a non-organized market within which the agents exchange, through intermediaries or brokers, contracts with financial liquidation designed according to their preferences and without subjecting to rules of participation and negotiation [12].
- Market of bilateral contracts: it consists of a non-organized market in which the parties exchange contracts bilaterally, also known as Power Purchase Agreements (PPA), both by physical and financial liquidation and designed according to their necessities [12].

2.1.2.2.- Spot market

The spot market is constituted by the daily, intraday and system adjustment services markets, and the subjects who participate in it, as market agents, are the electric power generators, the marketers (whether they are reference marketers or not), consumers (whether they are Direct Consumers in Market or not), the representatives, who act on behalf of a market subject, either in the name of the said subject (direct representation) or in their own name (indirect representation) [4].

As mentioned above, the daily and intraday markets are managed by the Market Operator (OMIE), whereas system adjustment services markets are organized by the Spanish System Operator, Red Eléctrica de España, S.A. (REE) [7].

Daily market

The daily production market is that in which transactions of acquisition and sale of electric power, with physical delivery for the next day, are established by a bid matching process. The contracting sessions of the daily market are organized in programming periods of one calendar hour, considering as a programming horizon the 24 consecutive programming periods [7].

The market agents effect their offers of sale and purchase of electric power to the Market Operator, for the programming period of the same programming horizon. The owners of the production units are obliged to submit bids up to the limit of their production capacity, except in case they have taken a bilateral contracting system by which they are excluded from the offers system [4].

Equally, reference marketers are obliged to conduct economic offers of acquisition of electric power in each programming period for the part of energy necessary for the supply of its costumers [6].

On the basis of their content, the said offers can be simple or complex, in the case of offers of sale, whereas the offers of purchase can be only simples. These ones consist of offers of sale and acquisition of energy for each programming period and sale or acquisition unit, with the expression of a price and an energy quantity, being able to exist for each programming period up to a maximum of 25 sections, with a different price for each section, being this increasing for the offers of sale, and decreasing for the offers of acquisition [4].

Complex offers, for its part, are those which, complying the requirements for simple offers, incorporate some of the following conditions [4]:

- a) *Indivisibility condition*: it allows to fix a minimum value of functioning in the first section of each hour [8].
- b) *Minimum income condition*: the offer is only understood presented for the purposes of matching if it gets a minimum income for the set of programming periods, expressed by a fixed quantity, in euros, and by a variable quantity, in euros per MWh.
- c) *Programmed stop condition*: it allows that, if the production unit has been removed from matching on account of not fulfilling the requested minimum condition, make a programmed stop within a maximum time of three hours [8].
- d) *Load gradient condition*: it establishes, for each unit of sale, a maximum difference of energy variation upwards or downwards, between two consecutives programming periods.

Before the closing of the daily market session (12:00), the Spanish and Portuguese System Operators put at Market Operator's disposal the information regarding the unavailability of production units, the maximum capacities for importation and exportation in each international interconnection, the notifications of use of capacity rights assigned in previous auction, the bilateral contracts received by the agents, as well as the energy nominations from auctions primary energy emission [4].

Before proceeding to the bid matching process, the Market Operator carries out certain verifications in relation to the agents and the established guarantees for the offers, paying special attention to their content [4].

It should be noted that, unlike "pay as bid" markets, where generators receive exactly the offered price, the daily market in Spain is of the marginalist type, that is, all the matched generators receive the same price, result of the crossing between the curves of supply and demand [9].

The matching process is carried out by the Euphemia algorithm, as a result of the cooperation agreement between diverse European market operators for the conducting of a unique common matching [4].

Firstly, the Market Operator establishes, for each programming period of the time horizon, the order of economic precedence of sales offers from the cheapest to the most expensive one, forming the aggregated curve of the sale offer ordered by ascendant price. The order of economic precedence of purchase offers is, conversely, from the most expensive to the cheapest one, so that the aggregated curve of the purchase offer will have a descending order. Once both curves are formed, conditions of complex offers are considered, after which the matching process is carried out [4].

The matching algorithm Euphemia looks for the optimization of the welfare, which corresponds to the sum, for the set of all the time periods of the programming horizon, of the profit of purchase offers (difference between the price of the matched purchase offer and the received marginal price), plus the profit of sale offers (difference between the received marginal price and the price of the matched sale offer), plus the congestion income due to limitation in the capacity of international interconnections [4].

The result of the match determines the marginal price for each programming period, which will be the price resulting from the balance between supply and demand of electric power offered in them, as well as the energy committed by each agent of the daily market based on the offers of purchase and sale assigned to the said match [7]. In case the interconnection between Spain and Portugal is saturated a market-splitting process is executed, by which different matches are made for Portuguese and Spanish agents, taking into account the maximum amount of energy exchangeable between both systems and resulting in a different marginal price for each country [9].

The Market Operator put at System Operator's disposal the Base Match Programme (PBC) who, after considering the bilateral contracts communicated before the closing of reception of offers to the daily market, establishes the Daily Operating Base Programme (PBF) [7].

As of the said programme, the System Operator determines, on one hand, restrictions for guarantee of supply, which refer to production considered necessary of thermal units that use autochthonous sources of combustion of primary energy. On the other, determines the technical restrictions of the system, which refer to any circumstance or incidence derived from the situation of the transport network of the system which, by affecting the safety, quality and reliability conditions for the supply, a modification in the programme is required [7].

Intraday market

The goal of the intraday market is to assist the adjustments that can be made in supply and demand of electric power after being fixed the Definitive Viable Programme (PVD) [7]. In it, market agents present offers of sale and acquisition by which adjust their programmes to their best forecasts of what they will need in real time [8].

At present, the intraday market is structured in six sessions whose opening hours are 17:00, 21:00, 01:00, 04:00, 08:00 and 12:00, having each of them, respectively, 27, 24, 20, 17, 13 and

9 programming periods of the same day on which the sessions are held (except the first intraday, whose programming horizon cover the last hours of the previous day) [8].

All the agents who had participated in the corresponding session of the daily market are enabled to present offers of sale and purchase of electric power in the intraday market. Likewise, the production units that had communicated their unavailability to the System Operator before the closing of the daily market and had recovered their availability, are also enabled. Lastly, the agents who had communicated previously to the System Operator the existence of a bilateral contract or capacity rights for the hours comprised in the corresponding session of the intraday market, are enabled to take part in the said session [4].

Unlike the daily market, in the intraday market it is possible to present multiple offers of sale and purchase for the same programming period and production or sale unit, which are treated independently. These can be simple or complex, due to their content. The simple offers indicate only a price and an energy quantity, being able to exist for each programming period up to a maximum of five sections, with a different price for each of them. The complex, on the contrary, are the ones which, fulfilling the requirements for the simple offers, incorporate some of the following conditions [4]:

- a) *Load gradient condition*: same as daily market.
- b) *Minimum income condition*: same as daily market. In the case of acquisition offers, this condition will be maximum payments, so that an offer is only understood as presented for the purposes of matching if the consequent payments are less than a maximum established.
- c) *Complete acceptance in matching of the first section of the sale offer*: in case of not being totally matched the first section of the offer, the offer is removed.
- d) *Complete acceptance in each hour in matching of the first section of the offer*: in case of not being totally matched the first section of an offer in a certain hour, all the sections corresponding to the said hour are removed, remaining valid the rest of the offer.
- e) *Minimum number of consecutive hours of complete acceptance of the first section of the offer*: in case not being totally matched the first section of the offer during a minimum number of consecutive hours, this offer is removed.
- f) *Maximum energy condition*: it allows supply units with limitations in the availability of energy make offers within all the hours of the programming horizon, limiting however the matched value to a maximum volume of total energy.

Before proceeding to the match process, the System Operator makes available to the Market Operator information regarding unavailability of production units, commercial capacities of international interconnections and capacity rights [4].

The Market Operator carries out the matching of purchase and sale offers of electric power by a simple matching method, obtaining independently the marginal price, as well as the energy volume accepted for each offer of sale and purchase, for each programming period. The said price corresponds to the cut-off point of the aggregated sale and purchase curves, formed analogously to the daily market [4] [8].

In the case of bids with complex conditions, gradient load condition is added to the result of the matching based on the previously mentioned method, obtaining the simple conditioned match.

By means of an iterative process, several simple conditioned matches are executed, until all the matched offers satisfy the declared complex conditions, being this solution the first provisional final solution. By another iterative process, the first definitive final solution is determined, which respects the commercial capacities of the international interconnections [8].

The Market Operator put at System Operator's disposal the incremental result of the match of each intraday market. This, in turn, communicate both the involved agents and the Market Operator the Final Schedule Programme (PHF), aggregating to the previous PHF (in the case of the first intraday, PVD) the result of the intraday market, as well as the relevant technical restrictions [4].

System adjustment services market

The objective of the adjustment services is to keep the electric system in physical balance and within an adequate security margin, and they are offered in different markets organized by the System Operator, REE [10].

Solution of technical restrictions

A technical restriction consists of any circumstance or incidence derived from the situation of generation-transport system which, by affecting the safety, quality and reliability conditions for the supply, a modification in the programme is required [7].

Once the PBC is obtained and taking into account the bilateral contracts notified previously to the closing of the session of the daily market, the System Operator verifies the viability of the resulting programme, identifying the technical restrictions which needs to be solved. For the resolution of these congestions, the generation programme is modified, applying technical safety criteria, as well as economic criteria, managing the offers sent by generators in order to increase or decrease the electric power production [10].

Supplementary services

The supplementary services (SSCC) are necessary for guaranteeing electric power supply in quality, reliability and security conditions, so that unbalances between generation and consumption can be solved in real time [7] [10]. The said services can be compulsory, without an additional remuneration, or optional, whose retribution is established by market mechanisms. The optional supplementary services are the following ones:

- a) *Additional power reserve to upload*: its goal is to provide the electric system with the necessary level of power reserve to upload, considering the available power reserve in the expected program of the daily horizon [11].
- b) *Secondary regulation*: it allows the System Operator to have a flexible reserve of available capacity in order to solve automatically significant unbalances between generation and demand. Once the necessary reserve of secondary regulation is estimated, in terms of power (MW), for guaranteeing supply in reliable conditions, the Market Operator convenes the corresponding market after the execution of the daily market and the one of technical restrictions. The generator companies, on a voluntary basis, present their offers of available capacity, a service that is retributed by two concepts: availability (power range) and the energy eventually used [10].

- c) *Tertiary regulation*: it is defined as the maximum variation in power that a production unit can carry out in a maximum time of 15 minutes, and that can be maintained, at least, during 2 hours. Its offer is mandatory and aims to restore the secondary power range in case having been used for any contingency. Unlike the secondary reserve, generators only receive income for this service if it is used by the System Operator [10] [11].

Deviations management

Deviations management's function is to solve deviations between generation and consumption that can be identified between the closing and the opening of two consecutive intraday markets. The agents communicate, during the normal operation, the forecasts of deviations caused by different reasons, to which variations in the forecast of renewable production carried out by the System Operator are added. The deviations management market is only convened when the expected deviations during the period between two consecutive intraday markets exceed 300 MW in half an hour, which consists of asking for offers to the generators in the opposite direction to the deviations foreseen in the system [10].

The extra cost due to deviations in the system managed by the System Operator (supplementary services and deviations management) is subsequently passed on to agents who have behaved against the needs of the system [10].

2.2.- Analysis of the energy sector

2.2.1.- Global outlook

In the New Policies Scenario considered by the International Energy Agency (IEA), which takes into account the policies that had been adopted as of mid-2015, together with relevant declared policy intentions, global energy demand is expected to grow by 30% between today and 2040, a significantly slower rate of growth than in the last decades [13]. All of this growth comes from fast-growing emerging economies, due to demographic expansion and a rising prosperity, which will allow more than 2.5 billion people lift from low incomes [14].

Global GDP growth, for its parts, is projected to average a rate of 3.4% per year [13], partly supported by population growth, but mainly driven by increasing productivity in developing countries [14]. This sustained economic growth, together with the slowing in demand growth as a result of accelerating gains in energy efficiency, decreases energy intensity even more quickly than in the past [14]. These tendencies are shown in Figure 1, which include the forecasts of the primary energy demand and the energy intensity for OECD and non-OECD countries.

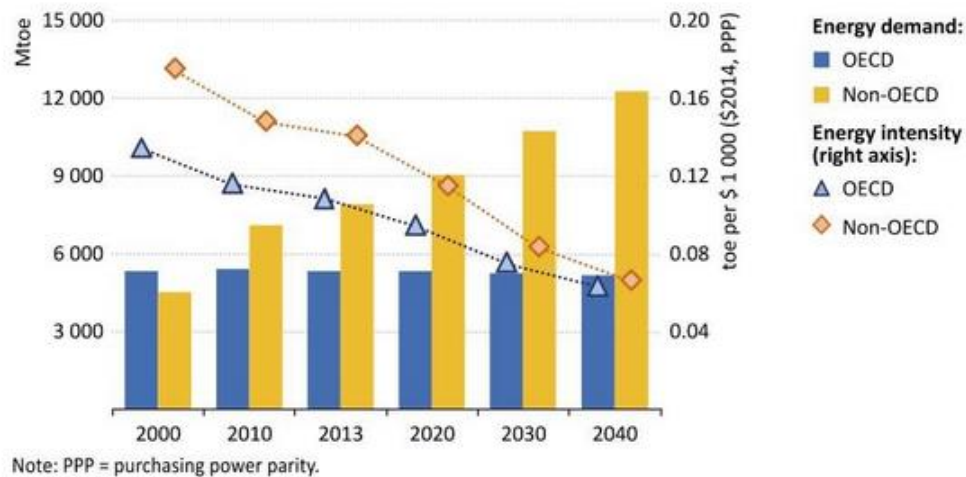


Figure 1: Primary energy demand (left) and energy intensity of GDP (right) in OECD and non-OECD countries [15]

China and India account for half of the growth in global energy demand, with clearly contrasting trends, however. The first's energy growth slows significantly to a rate of 1.5% per year, as it transitions to a more sustainable pattern of economic growth [14]. In contrast, India's demand growth slows less pronouncedly, due to its robust economic growth. As a result, India emerges as the world's largest growth market for energy, with a share of global energy use raising to 11% by 2040 [13]. Overall, developing countries in Asia account for two-thirds of global energy growth, having also an increasingly important role the Middle East and Africa [13]. Figure 2 shows the weight that different countries will have in 2040 with regard to the energy demand.

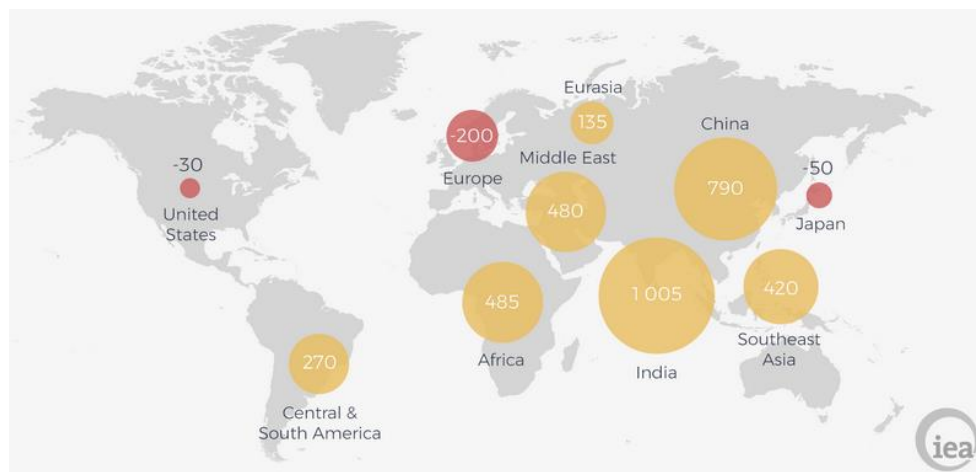


Figure 2: Change in primary energy demand, 2016-2040 (Mtoe) [13]

Energy demand in OECD countries declines 3% by 2040, led by EU in the transition towards a low carbon economy. This is supported by a range of policies regarding energy efficiency and promoting a shift towards lower carbon fuels. As a result, energy intensity falls materially, achieving, by 2040, 35% lower carbon emissions than in 2016. A shift to a lower carbon fuel mix also plays an important role, given that by 2040, non-fossil fuels provide around 40% of EU energy demand, considerably higher than the world average 25% [14]. Figure 3 shows the

forecasts for GDP, energy intensity and carbon intensity compared to 2000, as well as the share of each technology in the expected evolution of primary energy consumption in OECD countries.

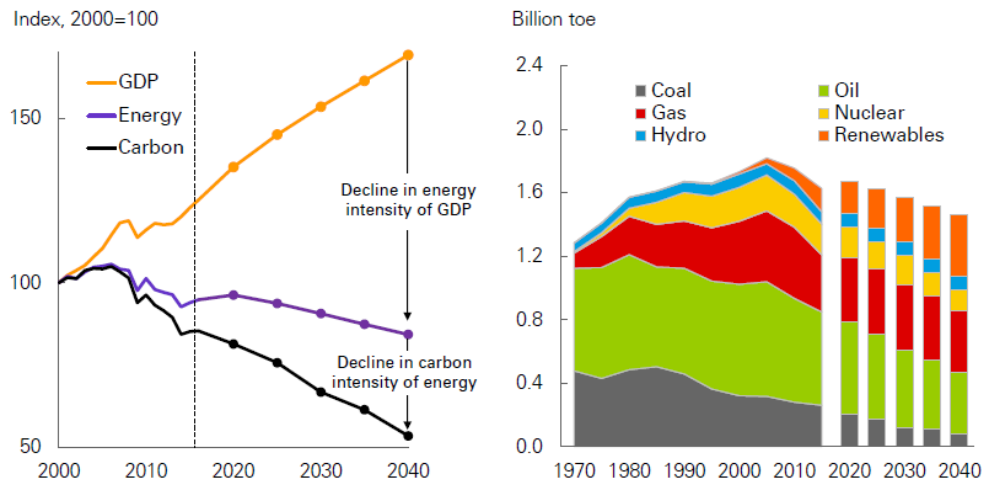


Figure 3: GDP, energy and carbon emissions (left) and primary energy consumption (right) [14]

Worldwide, the transition towards a lower carbon fuel mix is also set to continue. Renewable energy is expected to grow at a rate of 7% per year, accounting for over 40% of the increase in energy supplies, the largest contribution of any energy source [14]. Natural gas, for its part, grows much faster than either oil or coal (1.6% p.a.), overtaking coal and converging oil by 2040 [14]. The latter's demand continues to grow to 2040, driven mainly by transport sector in emerging economies, albeit at a steadily decreasing pace (0.5% p.a.) [14]. Coal consumption will increase at a rate of 0.4% per year, a marked slowdown compared with the 2.4% average of the past 25 years [15], with its share in primary energy declining to 21%, its lowest share since the industrial revolution [14]. Lastly, nuclear and hydro power outputs continue to grow, albeit slower than in the past, at rates of 1.8% p.a. and 1.3% p.a., respectively [14]. Figure 4 includes the forecasts of the primary energy consumption by each technology, their share in primary energy consumption as a percentage and the share of fossil fuels.

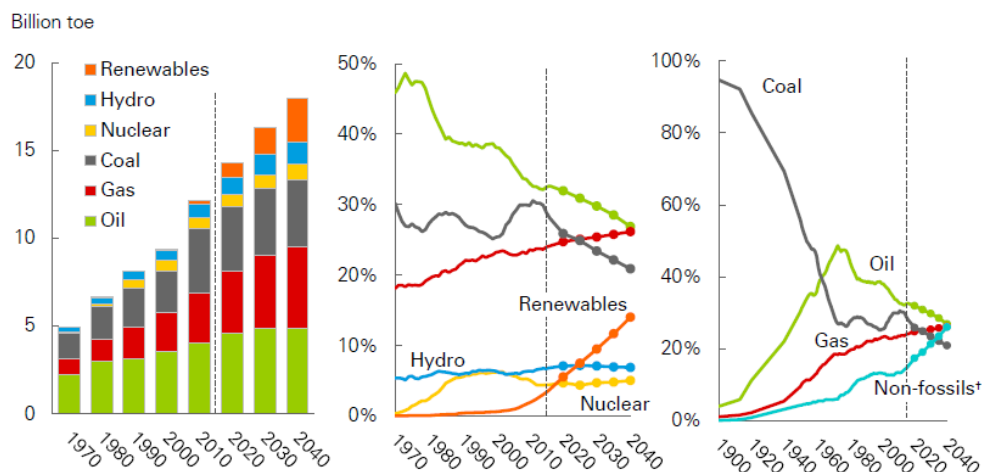


Figure 4: Primary energy consumption by fuels (left) and shares of primary energy (right) [14]

Growth in electricity demand and GDP gradually begin to decouple, due to efficiency improvements and a decay of energy-intensive industry in OECD countries, resulting in a modest

decline in electricity intensity [15]. Nonetheless, electricity is the rising force among worldwide energy demand, accounting almost 70% of its increase, with power demand growing three times more quickly than other energy [14]. As a result, electricity's share of primary energy in total final consumption rises from 18% in 2013 to 24% by 2040, driven by non-OECD countries and their increasing use of electricity in industries, the ongoing shift of people to urban centres and rising prosperity [15]. Figure 5 shows the comparison between the increase of GDP, power, total primary energy and primary energy without taking into account power generation. It also includes on the right the forecasts for each technology of the share of total power generation in OECD countries.

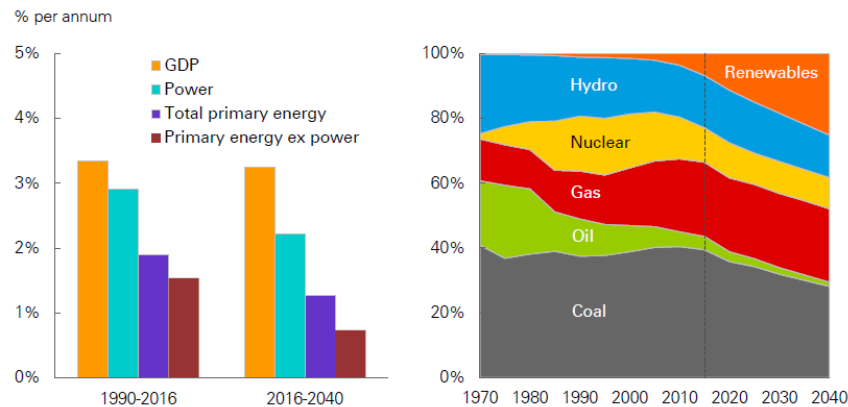


Figure 5: GDP, power and primary energy (left) and shares of total power generation in OECD countries (right) [14]

Modern renewables account for half of the increase in power and their share in total power generation rises from 7% today to 25% by 2040 [14]. As a result, they become a mainstream source of energy, one of the most important low-carbon sources for electricity and an essential part of climate change policies [15]. This increase is driven by the OECD and China, with coal-powered generation falling in the first and starting to decline in the latter from around 2030 [14].

In effect, OECD countries' share of coal-powered generation, which was 70% in 1990, almost halved by 2013, constituting 16% of the electricity generation mix by 2040, and having retired half of the existing fleet of coal-fired plant by this year. In contrast, coal-fired generation increases most in India, which faces particular challenges to satisfy rising energy demand as well as meeting energy security and environmental goals. Many Southeast Asian countries have also increased the role of coal in their energy mix, in response to their rising dependency on imported oil and natural gas [15]. As a result, coal still remains the largest source of power generation in 2040, with a share of 30%, approximately [14]. Figure 6 shows the differences between different countries in relation to their electricity mix, as well as the forecasts of the share of non-fossil and fossil fuels for each of them.

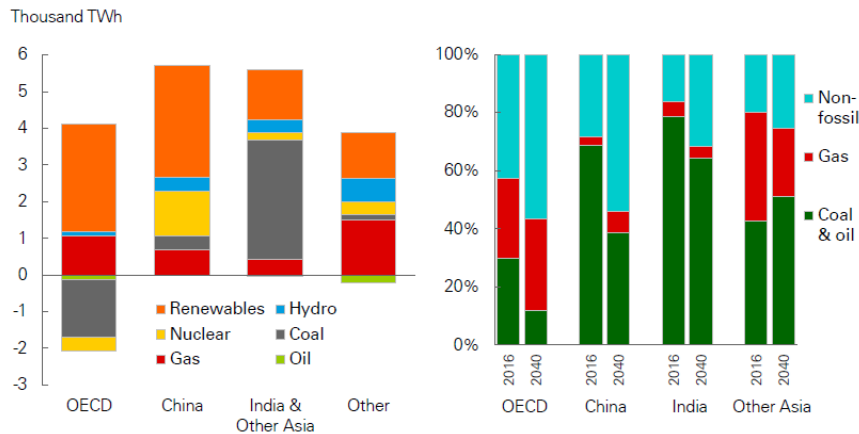


Figure 6: Growth and share of power generation by region, 2016-2040 [14]

Natural gas demand is projected to increase for many reasons, such as its relative abundance, its environmental advantages compared with other fossil fuels, as well as the flexibility and adaptability that make it a valuable component of a decarbonised electricity system [15]. However, its share is expected to be relatively flat at 20%, after its gradually rise of the past 25 years [14]. Regarding nuclear energy, 90% of its growth is driven by China, dampened by declines in both the EU and US, where aging nuclear plants are retired and not replaced. Growth in hydro power, for its part, is more broadly based across developing economies. Overall, their shares within power decline slightly, reaching together around a quarter of electricity generation by 2040 [14]. Finally, the share of oil in global generation carries on decreasing, from 4% to 1% [15].

Global cumulative investment in new power plants is expected to reach \$11.3 *trillion* over 2015-2040, rising global installed capacity from 6,163 *GW* in 2014 to 10,570 *GW* in 2040, an increase of over 4,400 *GW* [15]. The share of coal in total capacity falls from 31% in 2014 to 23% by 2040, whereas renewable capacity rises from 30% to 44% [15]. This capture two-thirds of global investment in power plants to 2040, becoming for many countries the least-cost source of new generation [13]. Figure 7 shows the global average annual net capacity additions by technology carried out until now, as well as the ones expected during the period 2017-2040.

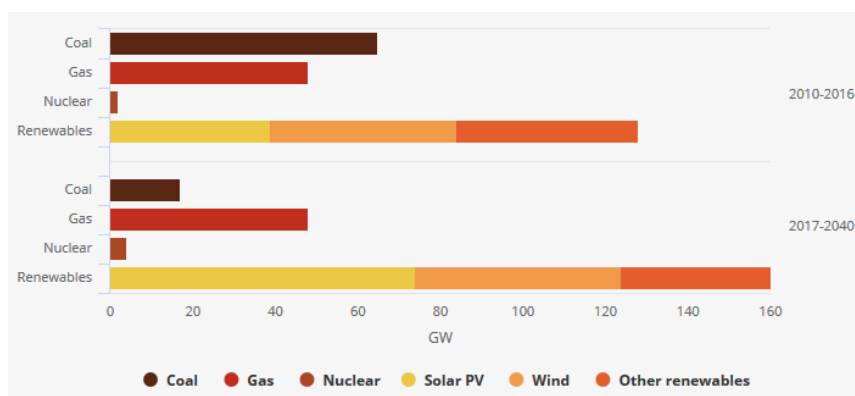


Figure 7: Global average annual net capacity additions by type [13]

In the EU, renewables account for 80% of new capacity, with wind power as the leading source of electricity soon after 2030, as a result of strong growth both onshore and offshore. Solar PV

firmly establishes itself as a key low-carbon technology in China and India, where due to its rapid deployment, it becomes the largest source of low-carbon capacity by 2040. China's choices will play a central role in the determination of global trends, being able to spark a faster clean energy transition [13].

Finally, the dramatic cost reductions achieved in some renewable technologies, especially in solar PV, has improved their competitiveness with other technologies, as a result of which global annual investment in renewable-based power plants is expected to climb steadily to over \$330 *billion* in 2040, averaging \$270 *billion* per year over the period 2015-2040. Thus, average costs of power generation technologies tend to converge in the next years, with falling costs for modern renewables and increasing fuel prices [15]. Figure 8 shows the change that is expected for the total power generation costs in the world during the period 2020-2040.

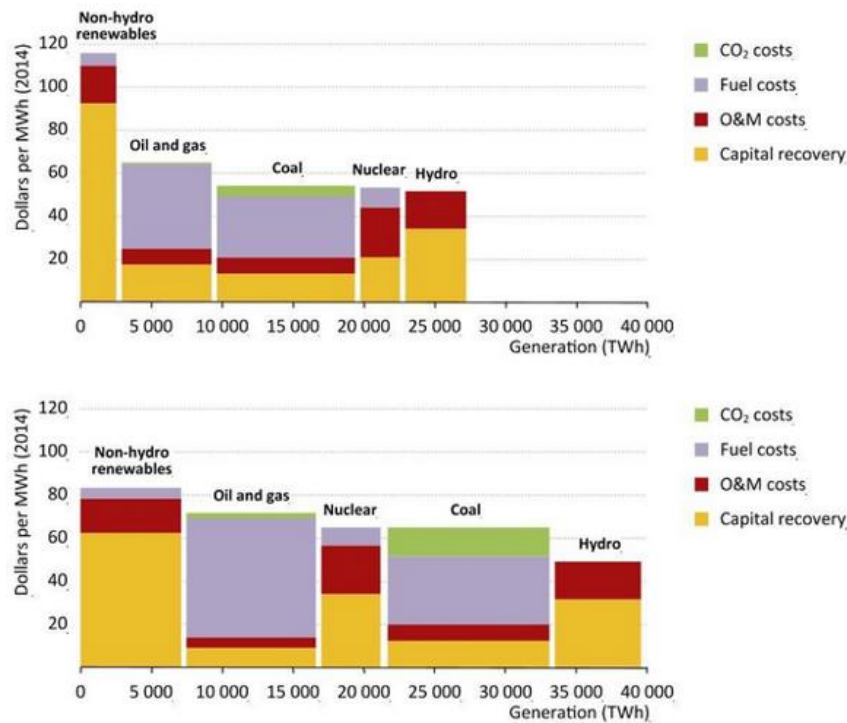


Figure 8: Comparison of total power generation costs in the world between 2020 (above) and 2040 (below) [15]

2.2.2.- Spanish energy system

2.2.2.1.- Primary energy

According to global forecasts, primary energy consumption in the European Union has slowed down in recent decades, mainly due to policies aimed at energy efficiency. Between 1996 and 2007 the UE had an average growth rate of 0.4% per year, reaching in 2006 a maximum consumption of 77,025,813 Tj [16]. Between 2007 and 2014 consumption decreased at a rate of 1.7% per year [16], due to an increase in fossil fuels' prices between 2006 and 2012, as well as to the economic crisis of many European countries [17].

This fact is reflected in its GDP growth, which averaged a rate of 4.8% per year between 1996 and 2006, falling down to a rate of 0.7% in the next 6 years [16]. From 2014 European GDP has

growth at an average rate of 2.9% per year, which has been noticed in consumption, that has grown slightly in the last years [16]. Nevertheless, primary energy consumption has declined 5% in the last 20 years, a tendency that is expected to be accentuated in the future [16]. Figure 9 shows the variation of primary energy consumption of the most important countries in Europe compared to the values from 1996. It also includes the average evolution of European Union, in order to compare the situation of each country with average values.

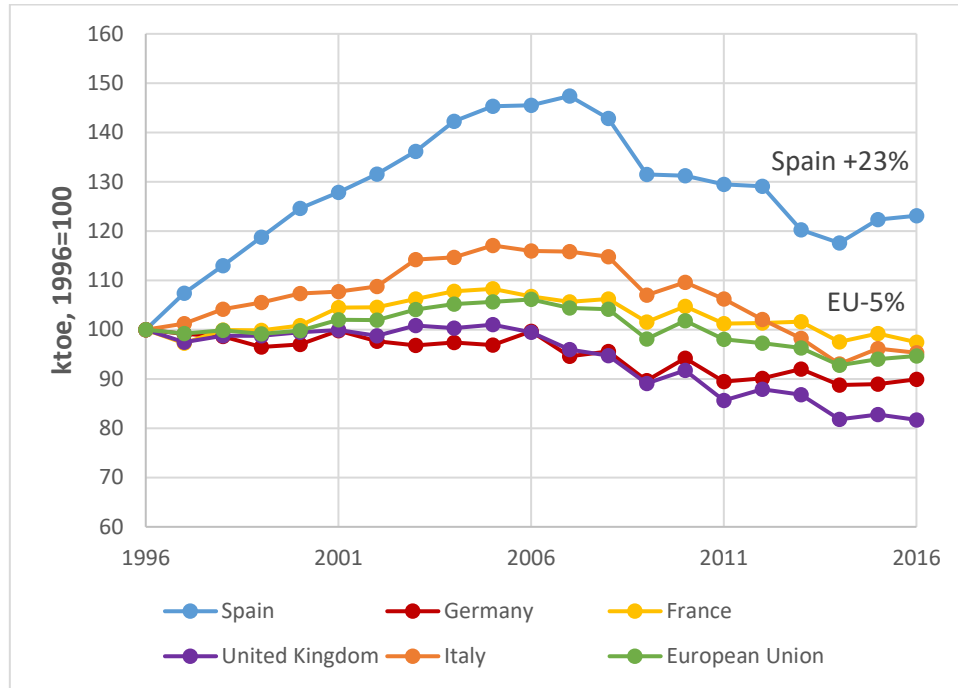


Figure 9: Variation of primary energy consumption with respect to 1996 (Co-adapted from [16])

Between 1996 and 2007 primary energy consumption in Spain increased at a much higher rate than the European average, 3.6% per year approximately, reaching in 2007 the historic peak of 6,124,630 TJ [16]. As a result of the economic crisis, whose effects were accentuated in Spain given its high energy dependence, consumption has been decreasing until 2014 at an average rate of 3.2% per year, showing however a slight rebound in recent years [16]. In contrast with other European countries, though, primary energy consumption in Spain has increased 23% in the last two decades, which evidences a need to promote policies in energy efficiency [16].

Despite the increase in consumption, however, energy intensity levels in Spain have remained practically the same as in the EU, suffering a 44% reduction in the last 20 years (see Figure 10) [16]. This is a result of the lower primary energy consumption per capita of Spain in comparison to European average, as well as a greater increase of its GDP in the last 20 years, 4.1% per year concretely, against 3.3% of the European Union [16].

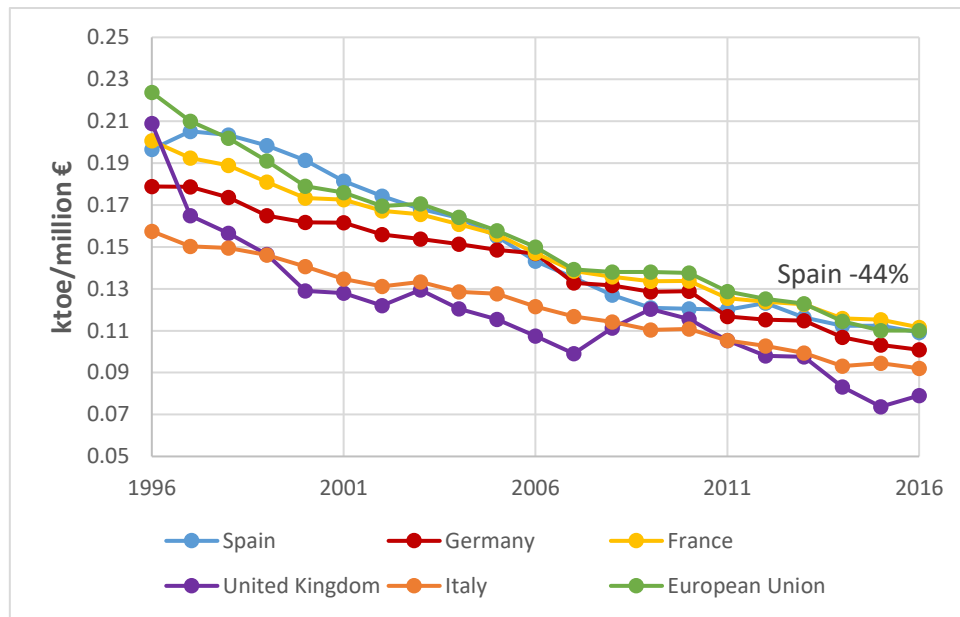


Figure 10: Evolution of energy intensity (Co-adapted from [16])

2.2.2.2.- Energy dependence

Excepting uranium, coal (in recession) and renewables, Spain does not have its own energy raw materials [18]. This fact, together with the high consumption of fossil fuels, make Spain one of the most energy-dependent countries in the EU, having to import more than 70% of primary energy [16]. Figure 11 shows the energy dependence in 2016 of the state members of European Union.

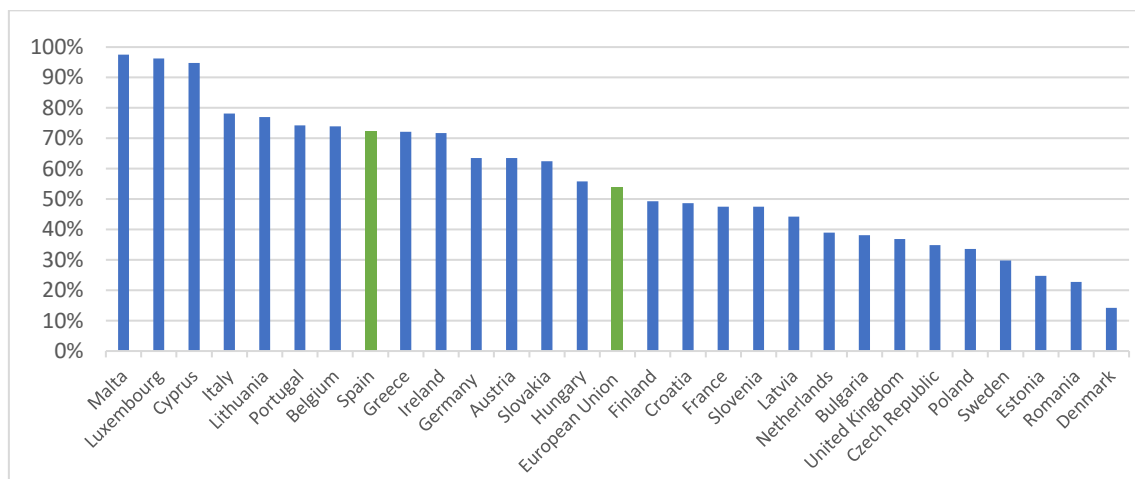


Figure 11: Energy dependence in 2016 of European countries (Co-adapted from [16])

Moreover, as it can be appreciated in Figure 12, the evolution of energy dependence has not changed in the last 20 years, being significantly superior to the European average [16]. As a consequence, energy prices and security of supply in Spain depend considerably on the international energy context, being therefore more vulnerable [18].

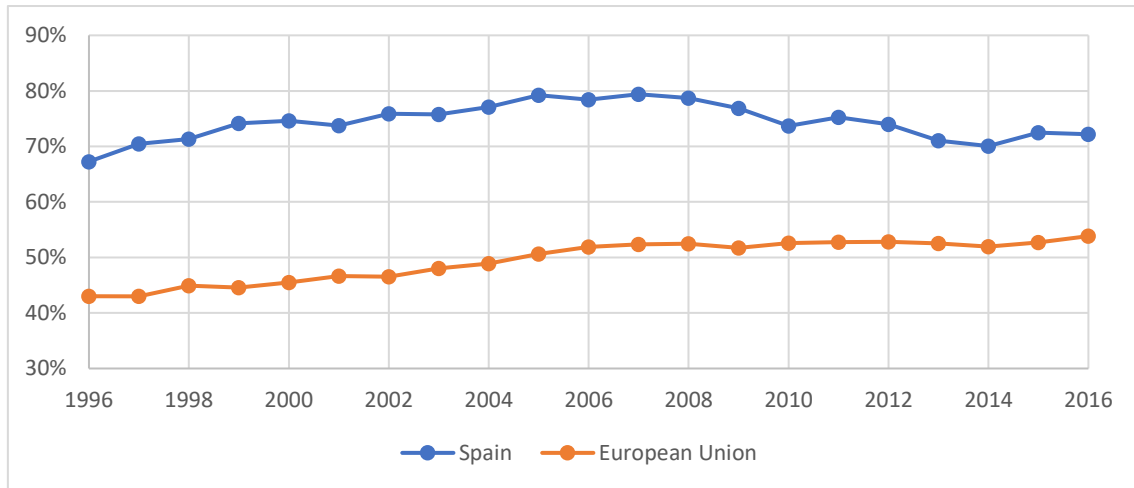


Figure 12: Evolution of energy dependence (Co-adapted from [16])

It should be noted, however, that supply of energy raw materials is carried out through numerous suppliers and in a diverse way, reducing the vulnerability of the energy system in terms of security of supply [18]. As an example, in 2016 natural gas supply structure was made up of nine countries, being the main supplier Algeria, with a percentage of 56.7% (see Figure 13) [19].

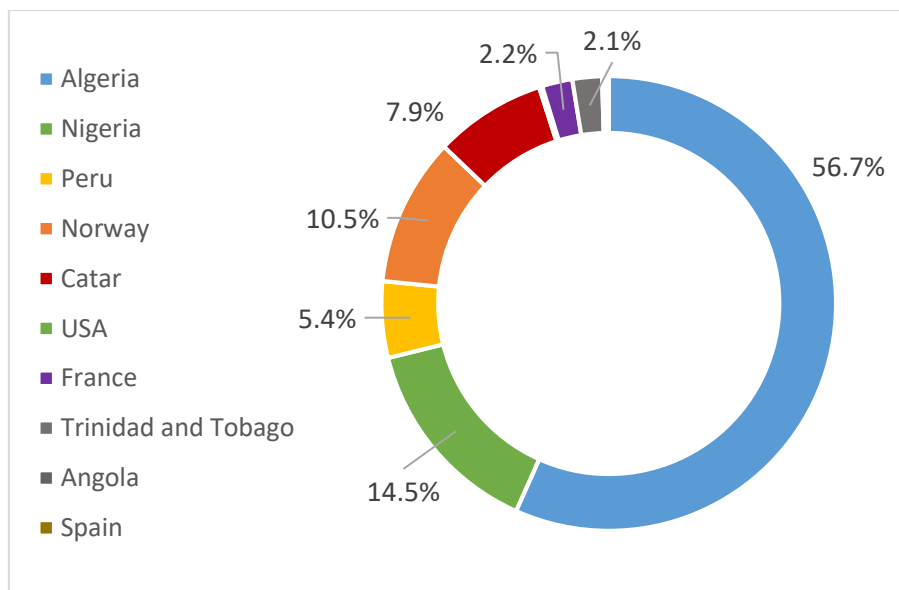


Figure 13: Natural gas supply by countries in 2016 (Co-adapted from [19])

2.2.2.3.- CO₂ emissions

After the commitments made in 1998 in terms of reducing greenhouse gases (GHG), in 2007 Spain was far from meeting its Kyoto targets, reaching 154.5% of emissions compared to 1990, against the goal of 115% for 2012 [16]. As of 2007, however, emissions have been reduced at an average rate of 3% per year, reaching in 2012 124.5% of emissions of base year, and 119.4% in 2015 [16]. Figure 14 shows the evolution of GHG of different countries and European Union compared to the values from 1990.

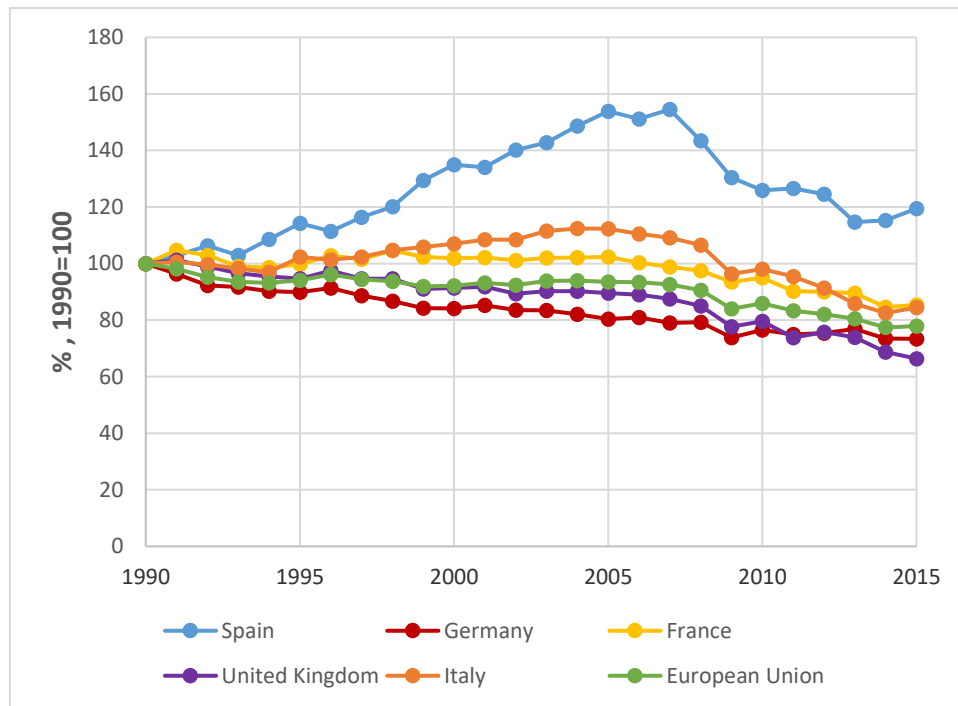


Figure 14: Evolution of greenhouse gas emissions with respect to 1990 (Co-adapted from [16])

It should be pointed out that, despite the unfulfillment of the goals established in the framework of Kyoto Protocol, emissions per capita in Spain are smaller than the European average, which have shown a bearish trend since 2000 (see Figure 15) [16]. In this sense, in future negotiations about emission objectives, Spain could turn out to be in a better position than the current degree of unfulfillment in relation to the Kyoto Protocol [19].

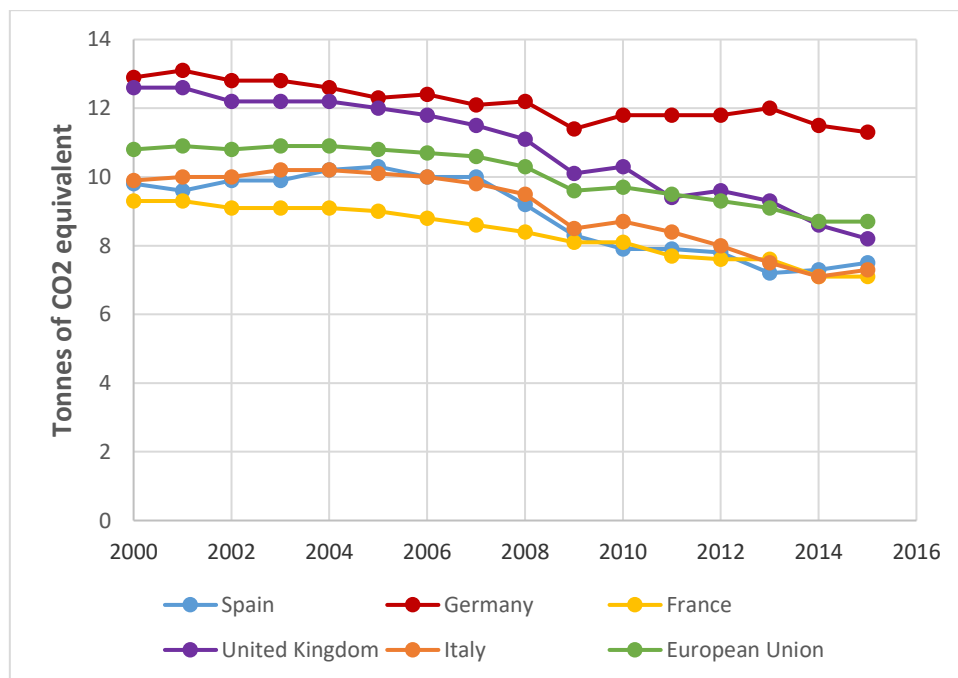


Figure 15: Evolution of greenhouse gas emissions per capita (Co-adapted from [16])

Lastly, both total and specific emissions have decreased considerably in the period 1995-2009, falling from 0.4 $MtCO_2/MWh$ in 1995 to 0.29 $MtCO_2/MWh$ in 2009 [19]. As of this year, emissions have fluctuated through the years around an average value of 0.27 $MtCO_2/MWh$, depending mainly on climate conditions and renewable generation (see Figure 16) [20].

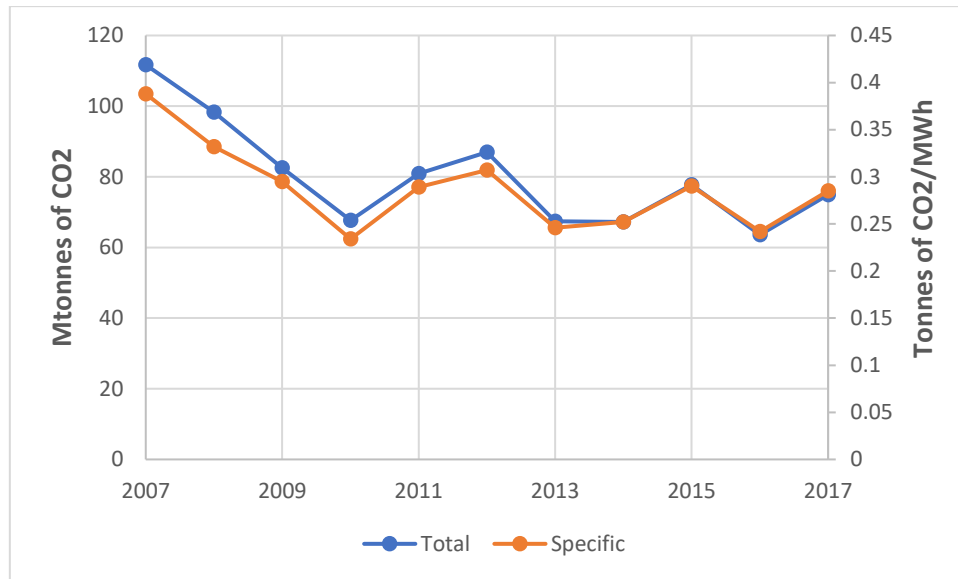


Figure 16: Evolution of total (left) and specific (right) emissions in power generation (Co-adapted from [20])

2.2.2.4.- Electricity sector

As well as a reduction in primary energy consumption, both at a global and European level, an electrification process is being observed, that is, an increase of the weight of electricity in final energy consumption. In 2016, gross electricity demand in Spain was 265,009 GWh , representing 16.4% of total energy consumption, compared to 14.6% of European Union [16]. Figure 17 shows this increase of electricity in final energy consumption between 1996 and 2016.

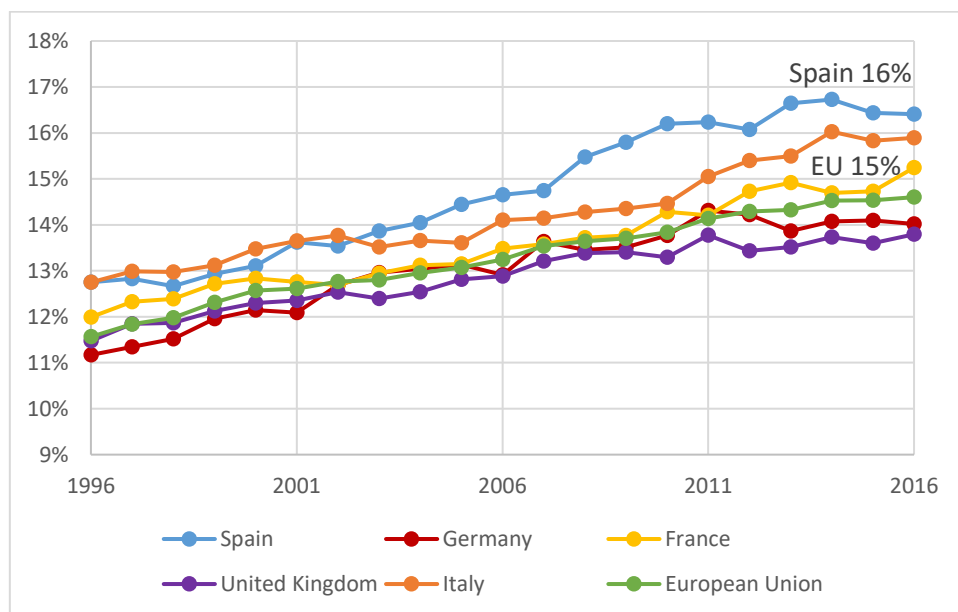


Figure 17: Share of electricity in final energy consumption (Co-adapted from [16])

Power generation, for its part, has decreased at an average rate of 0.9% per year in the last decade, establishing in 262,645 GWh, 8.9% less than values registered prior to the crisis [20]. Nuclear power has been the first source of electricity generation in Spain in the last 7 years, accounting for 21.2% of total [20]. Coal, for its part, remains as one of the main sources of generation, with a share of 17.2% in Spanish electrical mix [20].

Among renewables, wind power is the most important with a participation of 18.2% in national electricity generation, followed by hydro with 7.9% [20]. As a result of hydrological conditions, this technology presents considerable variations over the years, which have a relevant impact on renewable generation from one year to the next [20].

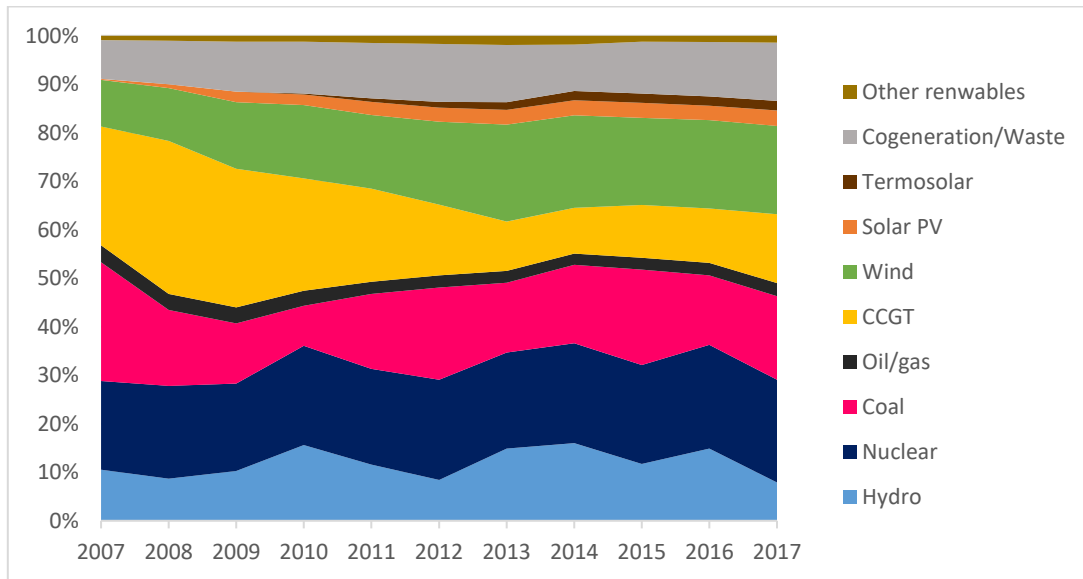


Figure 18: Share of technologies in electricity generation (Co-adapted from [20])

Overall, however, penetration of renewable energies in power generation is much higher than European average, showing an increase of 15 percentage points from 2004 and establishing in the current share of 37% (see Figure 19) [16].

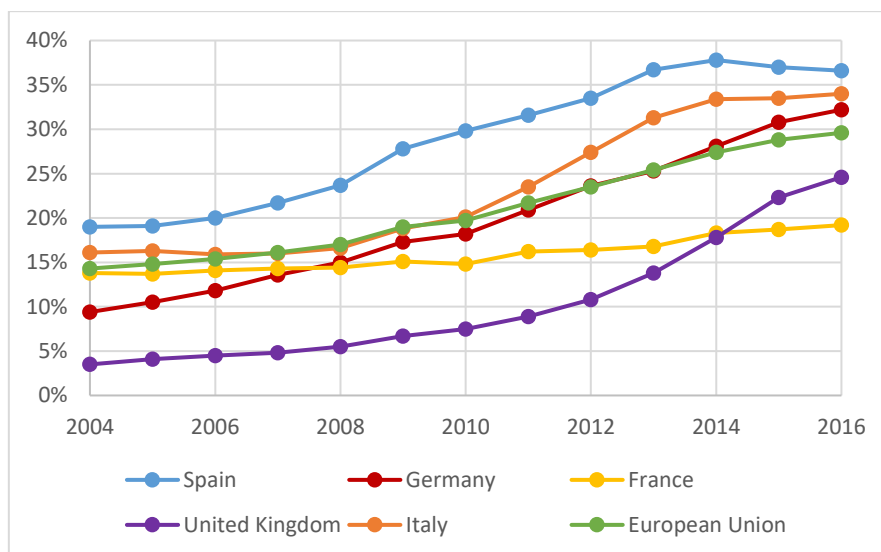


Figure 19: Share of renewable energy in electricity (Co-adapted from [16])

In general, wind energy has been the most implemented technology in the last decade, doubling practically its share in national electricity generation. Combined Cycle Gas Turbines (CCGT) are the ones which have reduced most, falling from 24.5% in 2007 to 14.2% in 2017, followed by coal, which has decreased its share more than 7 percentage points [20]. Solar energy, for its part, represents approximately 5% of current generation, going from 492 *GWh* in 2007 to 2,108 *GWh* in 2017 [20]. Figure 20 shows the change that each technology has undergone with regard to its share in electricity generation between 2007 and 2017.

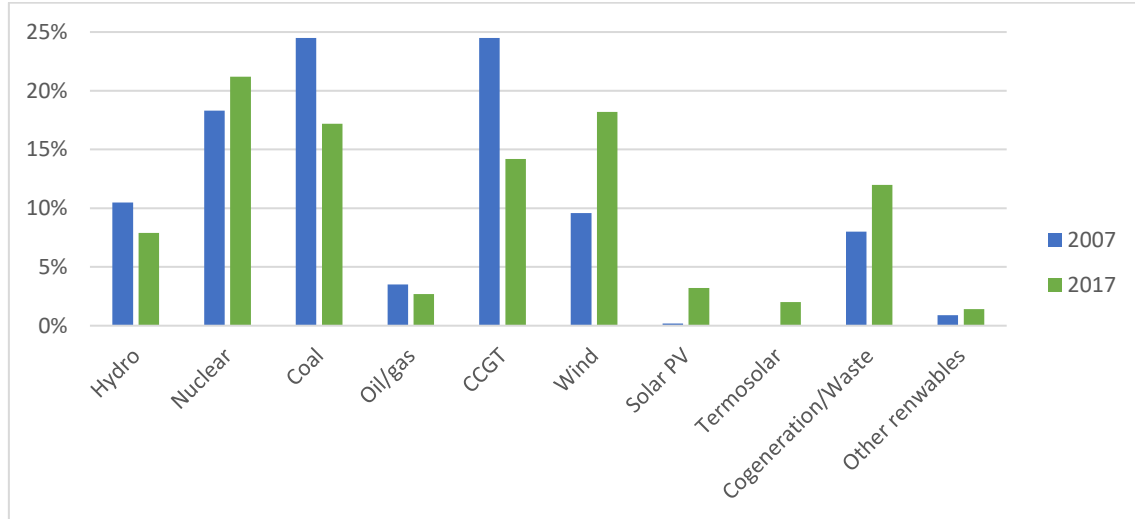


Figure 20: Comparison of share in electricity generation by technologies between 2007 and 2017 (Co-adapted from [20])

Spanish power generation mix has undergone deep transformations in the last 20 years, characterized by an impressive increase of renewable energies and natural gas [22]. Nowadays, Spain has a well-diversified electricity generation park, with 104 *GW* on installed capacity, of which 26% are CCGT plants, 22% wind and 20% hydro [20]. Figure 21 shows the current share of each technology with regard to its install capacity.

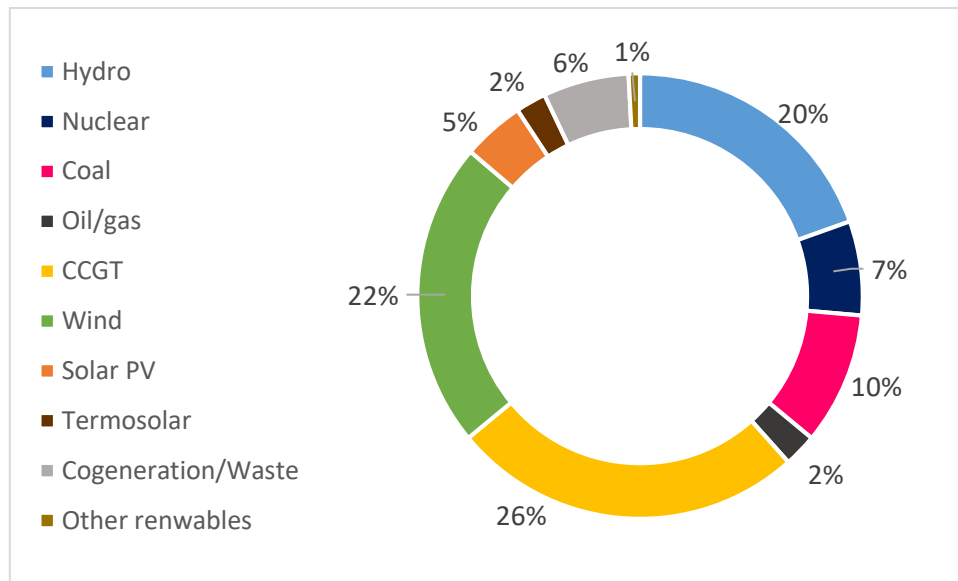


Figure 21: Share of technologies in electricity generation capacity in 2017 (Co-adapted from [20])

In the last 5 years, nevertheless, installed capacity has remained practically constant, as a result of an excess capacity resulting from the incorporation of 23,000 MW of CCGTs, as well as 24,000 MW of renewables in the period 2000-2010 [17]. This excess has been reflected in the increase of the minimum coverage index of recent years (defined as the ratio between the power available in the system and the peak power demanded during the year). Compared to the reference value of 1.1 usually used to define a properly sized park, in Spain the minimum coverage index reached a value of 1.45 in 2014, as shown in Figure 22 [20].

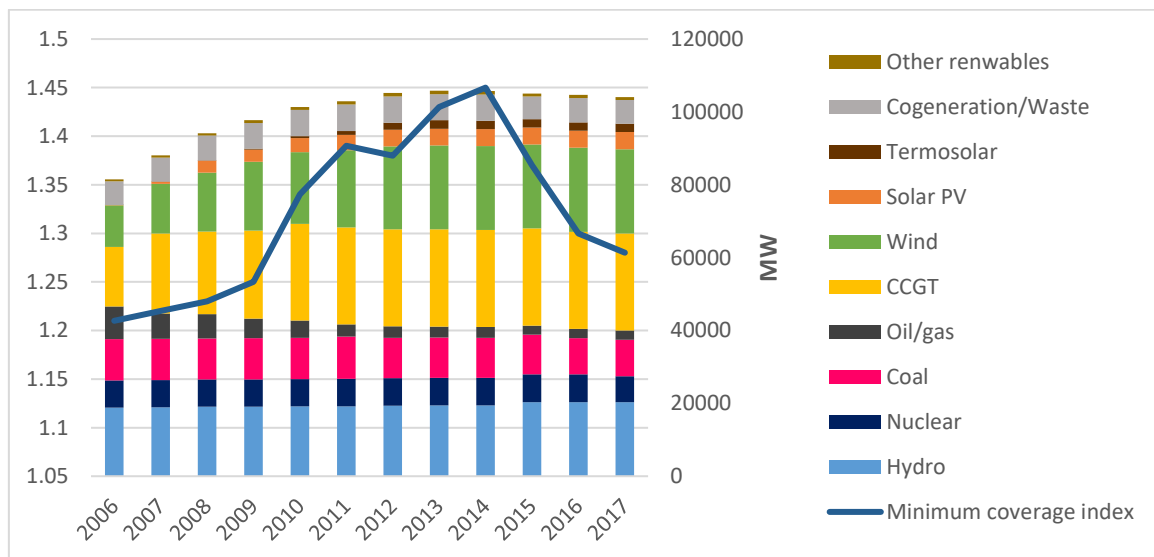


Figure 22: Minimum coverage index (left) and the evolution of electricity generation capacity by technology (right) (Co-adapted from [8])

This fact has had a special impact on combined CCGT power plants, which is the thermal technology that has experienced the greatest development in Spain during the first decade of 21st century [26]. Between 2002 and 2010, CCGT power increased at an average of 32% per

year, which is equivalent to an addition of more than 3 GW per year in this period (see Figure 23) [26].

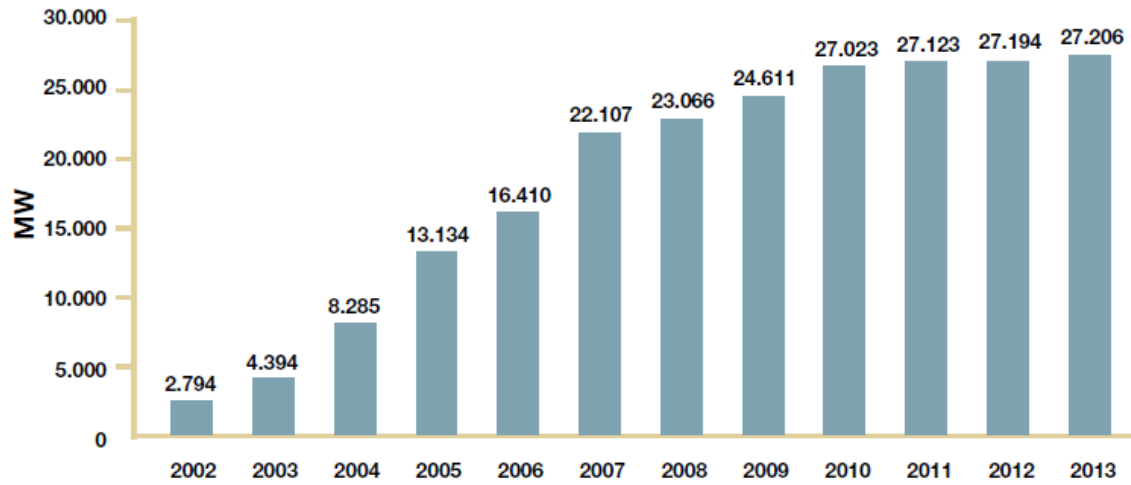


Figure 23: Installed capacity of CCGT 2002-2013 [26]

This technology was expected to play a central role in the Spanish electricity sector as a base technology, mitigating the deficit in Spanish generation capacity since the late 1990s. Its flexibility in operation, environmental efficiency compared to more CO₂ emitters thermal technologies, as well as its short period in the development of the project, stand out as its main advantages [26]. Nonetheless, CCGTs have not developed all the attractiveness that drove initial investments, being today underutilized and with a doubtful economic viability [26].

The main reason for that is the great penetration of renewable energies happened in the Spanish electricity sector, specially wind power, which have reduced drastically the share of CCGTs in the generation mix [26]. Figure 24 shows the installed capacity of the different renewable technologies during the period 1990-2013.

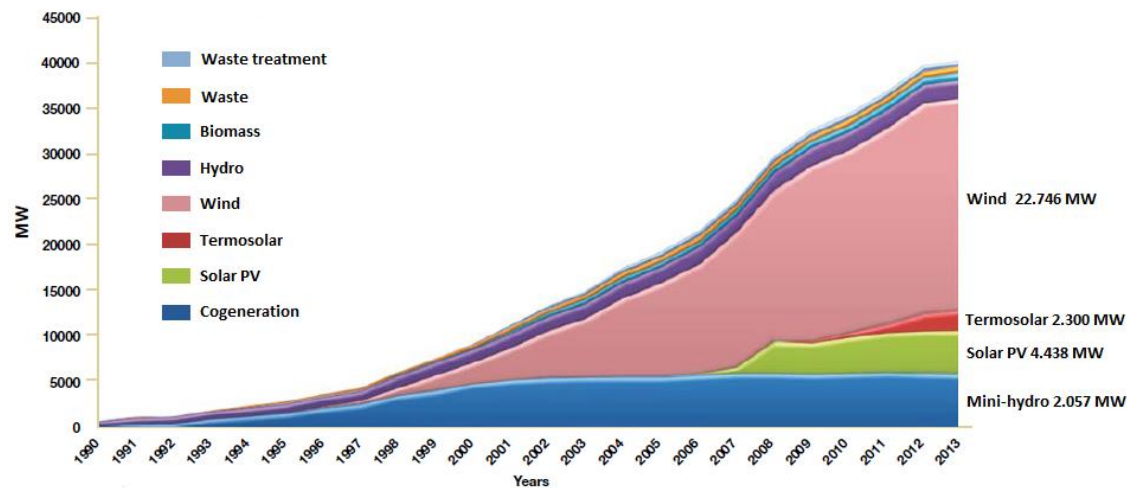


Figure 24: Installed capacity of renewable energies 2002-2013 [26]

As a result, in the last years this technology has turned out to perform a role of backup technology and coverage of system tips, reducing its load factor from 48% in 2008 to 11% in

2013 [26]. Despite the slight increase of its share happening in the last years due to the standstill of new installed capacity, the current load factor of 16% is very far from the 45% or 50% foreseen in initial investment decisions [26] [27]. Figure 25 shows this tendency, expressed in Equivalent Operating Hours (EOH), which represents the number of hours operating at maximum power that are needed to generate the same amount of energy.

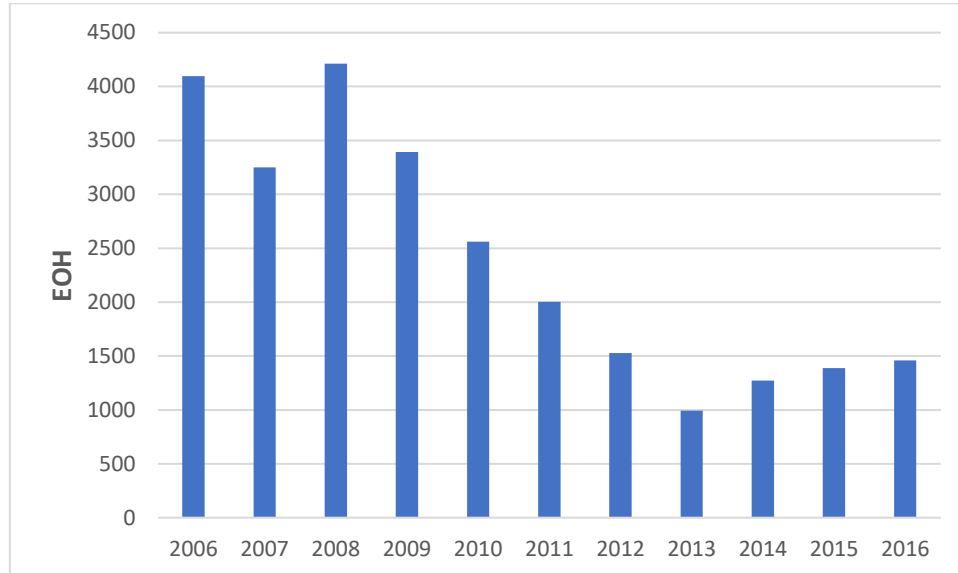


Figure 25: EOH of CCGT 2006-2016 (Co-adapted from [27])

Likewise, given the low variable cost of renewables, the price of electricity negotiated in the markets has been reduced, affecting directly the profitability of CCGTs. Since the liberalization of the electricity sector, it has been tried to ensure the profitability of marginal technologies through capacity mechanisms that could complement energy-only markets. Nevertheless, the regulatory design of capacity payments has been erratic and significantly reduced in recent years, preventing CCGTs from the necessary profitability [26].

Finally, among other reasons, it is worth mentioning the standstill of Spanish electricity consumption due to the economic crisis, the decrease in coal process as a consequence of shale gas and oil in the United States, as well as the decrease of the price in European market of CO₂ emission rights in the period 2011-2014 [26].

2.2.2.5.- International exchanges

Spanish electricity system is connected to three external electrical systems across the borders with France, Portugal and Morocco, which allow imports and exports of electricity (see Figure 26). Due to its geographical characteristics, though, the Iberian Peninsula is relatively isolated in terms of energy supply, with an interconnection ratio of 5% (sum of import capacities compared to installed generation capacity) [21].

Taking into account that real support can only come from Central Europe through the French border, the current interconnection ratio is 2.8%, which makes Spain practically an electric island [21]. In 2020, Spain will be the only country in Continental Europe below the objective of 10% set by the European Union for this year [21].

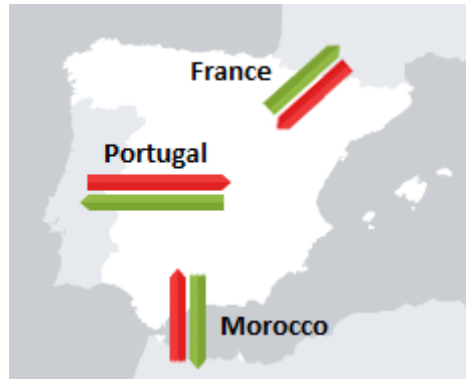


Figure 26: Interconnections with France, Portugal and Morocco

In 2017, the volume of the energy exchanged through the said countries stood at 38,347 *GWh* [20]. Imports reached 23,759 *GWh*, which have increased at an average rate of 25% per year since 2012, whereas exports remained at 14,588 *GWh* [20]. Net balance turned out to be importer for second consecutive year, after an export period of more than 10 years (see Figure 27) [20].

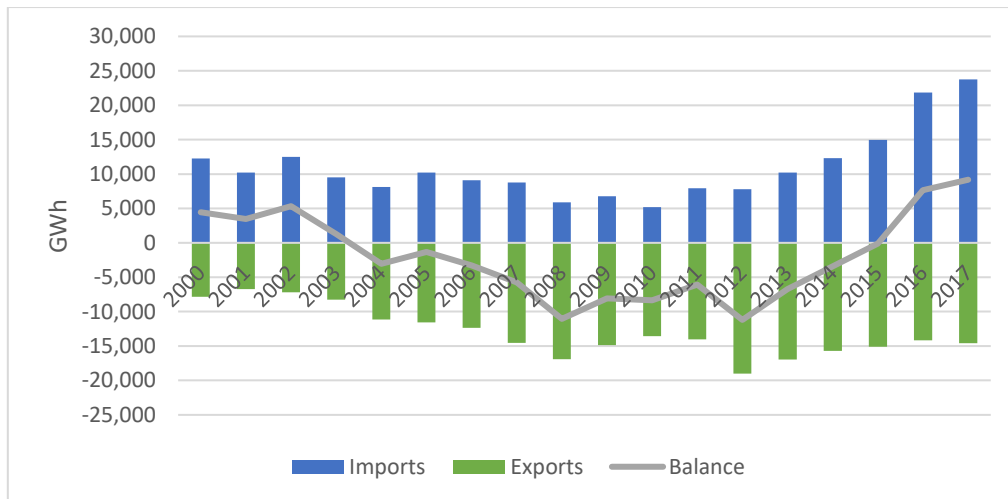


Figure 27: Evolution of international exchanges (Co-adapted from [20])

2.2.2.6.- Electricity markets

In 2017, the average final price in Spanish electricity market was 60.55 €/GWh, 25% higher than last year, getting closer to the price of 62.84 €/GWh recorded in 2015 [20]. Daily and intraday markets constituted 88% of the electricity price, system adjustment services 4%, capacity payments 4% and interruptibility services 3% (see Figure 28) [20]. Most of the increase in electricity price registered in the last year has been due to daily and intraday markets, whose average price has risen from 40.63 €/GWh to 53.42 €/GWh, an increase of 31% [20]. Among system adjustment services, for their part, technical restrictions accounted for 61% of the price, while the contribution of secondary regulation was 27% [20].

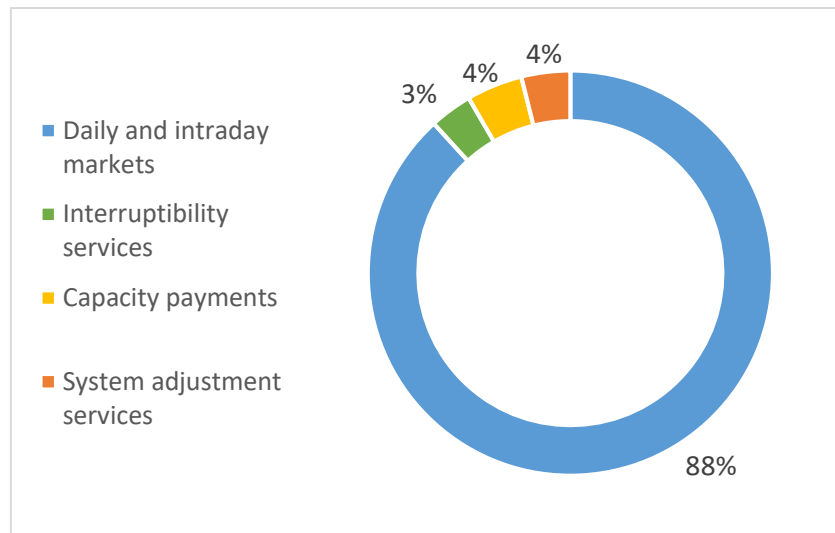


Figure 28: Final price components in 2017 (Co-adapted from [20])

This rise was mainly due to the fall of renewable sources in the generation structure, whose share reduced from 40.8% in 2016 to 33.3% in the last year [20]. Lack of water and wind, together with the scarcity of solar generation facilities, turned out in an increase in coal and natural gas consumption, whose prices raised precisely in this year [22]. Consequently, 2017 has shown a general increase of the price over the year, as shown in Figure 29.

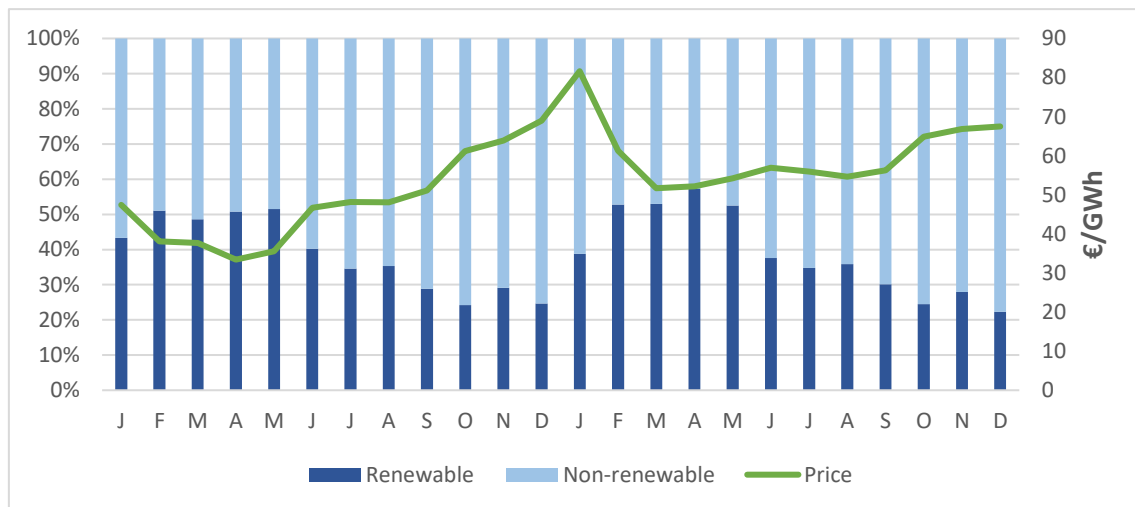


Figure 29: Relation between renewable generation and electricity price in 2016 and 2017 (Co-adapted from [20])

According to REE about the year 2016, energy in the daily market reached 250 TWh, of which 73.6% was deal in the spot market and the remaining 26.4% through bilateral contracts [23]. The said values have remained very similar since 2010, with an average value of 72.5% for the first and 27.5% for the latter [23]. On the contrary, in the intraday market sales were at 35 TWh [24]. Altogether, 15,193 million € were traded, 37.8% more than last year [24]. Lastly, in comparison with the rest of European markets, price of Spanish daily market has been one of the highest along 2015 and 2016, without reaching the maximum price registered in Italia in July 2015 [23]. This can be seen in Figure 30, which includes the prices of the main European markets recorded in 2015 and 2016.

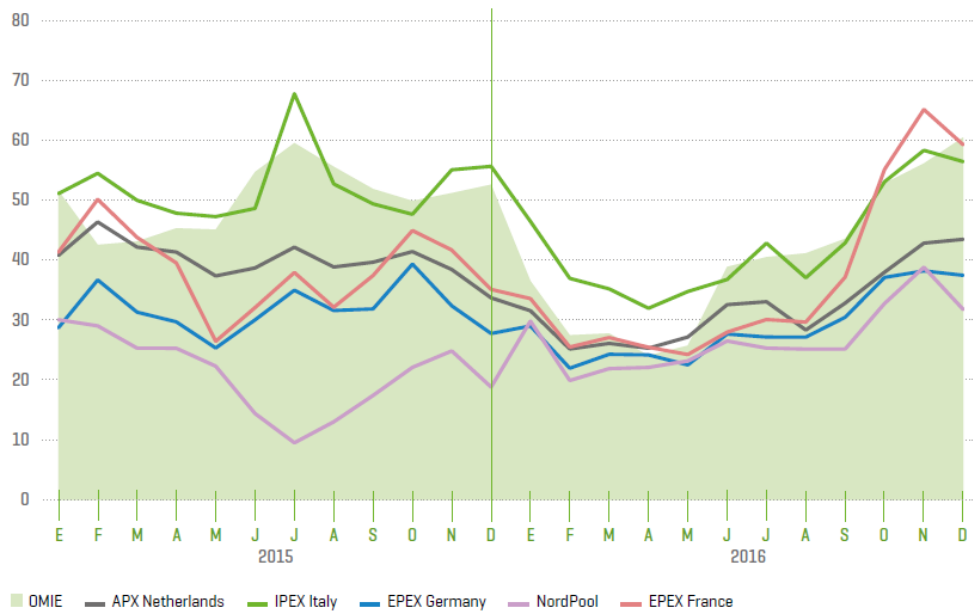


Figure 30: Prices of European daily markets in 2015 and 2016 [23]

2.2.2.7.- Energy transition

The expected evolution of the Spanish energy sector is subjected to the environmental objectives previously set, and considers that economic, technological and regulatory conditions will be developed in order to achieve these goals [25]. In this sense, international community acquired, in the Paris Agreement, the commitment to achieve emission neutrality between 2050 and 2010 [25]. The European Union, for its part, has established the objective of reducing GHG emissions between 80% and 95% in 2050 with regard to 1990 [25].

In order to achieve this objective, the European Union has established as intermediate milestones the 2013-2020 Energy and Climate Change Package, which aims a reduction of 20% with respect to 1990 levels, as well as the 2030 Framework, through which achieve a reduction of 40 % by 2030 (see Figure 31) [25].

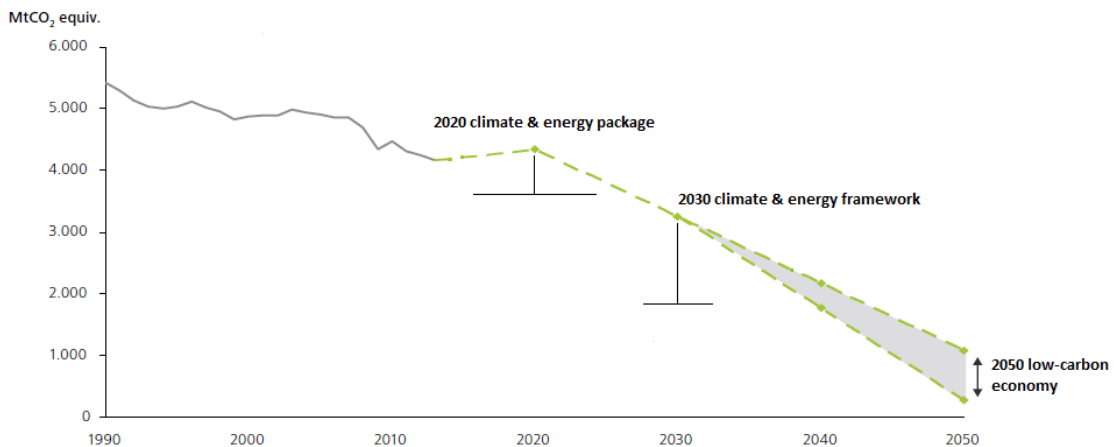


Figure 31: Evolution of greenhouse gas emissions of the European Union for the fulfilment of environmental objectives [25]

These commitments will mean for Spain a great reduction in GHG emissions, falling to a very low value of 14 $MtCO_2$, for which energy and non-energy uses will have to reduce their emissions significantly [25].

In order to fulfill the environmental objectives, current energy vectors are expected to be replaced by others with lower emissions, removing oil consumption and promoting electrification and use of other energy vectors with lower emissions, such as natural gas [25]. For that, a penetration of 100% of electric vehicles is expected in 2050, which requires that as of 2040 all sales of light vehicles will be electric [25].

Likewise, a shift to electric rail of between 40% and 60% is expected in heavy transport, which is currently carried out by road [25]. Lastly, energy vectors with lower emissions will be intensified in residential, industrial and services sectors, by means of electrification and gasification of consumption. With regard to electricity, concretely, it is expected to reach 65 – 67% of the primary energy consumption in 2050, compared to the current 42% [25].

The development of an electricity generation park based exclusively on renewable energies is one of the main step to fulfill in order to achieve the set goals. The future mix of electricity generation should reach up to 90 – 100% of renewable origin in 2050, which implies to install 145 – 201 *GW* of renewable capacity, essentially wind and solar PV [25]. Equally, in order to reduce energy intensity between at an average rate of 1.6% and 2.2% per year, implementation of energy efficiency measures will be necessary [25]. Figure 32 shows the forecasts for the final energy consumption by type of energy vector.

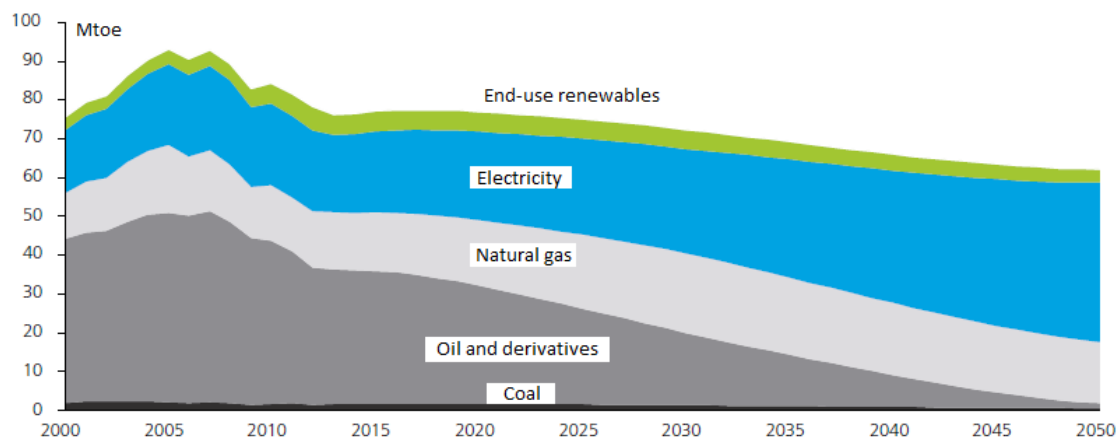


Figure 32: Evolution of final energy consumption by type of energy vector in Spain [25]

Investments that Spanish economy will need to carry out between 2016 and 2050 amount to a value of 330,000 and 385,000 *million* €, which is equivalent to an average investment of 10,000 *million* per year [25]. More than a half of the said investments will correspond to activities in power generation [25].

Decrease in energy dependence stands out among the benefits of decarbonization process, falling from 416 *million* barrels in 2013 to a consumption between 6 and 15 *million* in 2050 [25]. Mean price for consumers, for its part, will decrease to 65 – 75 €/MWh, far from the current 120 €/MWh [25]. Due to electrification, finally, total energy consumption is expected to diminish significantly, achieving thus a higher energy efficiency [25].

2.3.- Theoretical background of solar PV power generation plants

2.3.1.- Solar radiation

The Sun radiates an amount of $P_{sun} = 3.845 \cdot 10^{26} \text{ W}$ continuously in all directions. In order to calculate the fraction received by the Earth, a power density or radiation is considered, spreading this power over the area of a sphere around the Sun whose radius is equal to the distance to the Earth, that is, $r_{se} = 1.496 \cdot 10^{11} \text{ m}$ [28].

$$E_s = \frac{\text{Radiation power}}{\text{Area of sphere}} = \frac{P_{sun}}{4 \cdot \pi \cdot r_{se}^2} = 1367 \text{ W/m}^2 \text{ (Eq. 1)}$$

The result of 1367 W/m^2 is called the solar constant, which denotes the radiation outside the Earth's atmosphere. Nevertheless, the spectrum of the Sun changes when passing through it as a result of different phenomena, such as reflection of light by the atmosphere, absorption of light by molecules, Rayleigh scattering (due to particles smaller than the wavelength of the light) and scattering of large particles [28].

Therefore, in order to consider the path of the rays through the atmosphere, Air Mass AM is defined as a function of the solar altitude γ_s and which represents the extension of the path compared to the vertical distance through the atmosphere (see Figure 33).

$$AM = \frac{1}{\sin \gamma_s} \text{ (Eq. 2)}$$

The value of $AM = 1.5$ is established as the standard spectrum for measuring solar modules, with which the Earth receives 835 W/m^2 of the initial 1367 W/m^2 , called direct radiation [28].

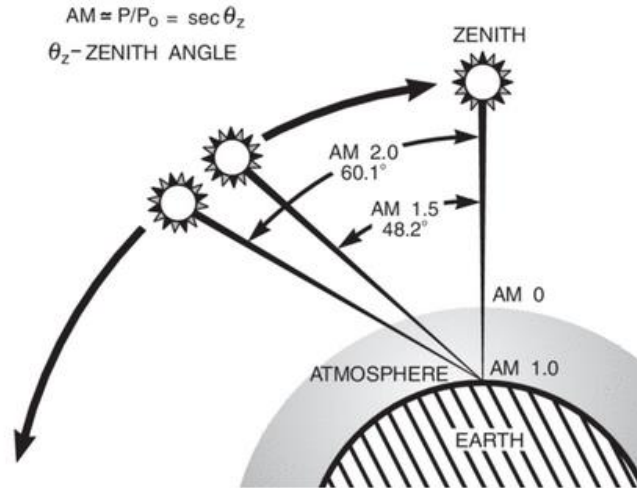


Figure 33: Variation of Air Mass depending on the position of the Sun [29]

On a clear summer's day, however, it is possible to measure on a surface vertical to the radiation of the Sun a global radiation value of $E_G = E_{STC} = 1000 \text{ W/m}^2$, as a result of which a factor of $1000/835 = 1.198$ is applied. These two values, together with a temperature of $T = 25^\circ\text{C}$, constitute the Standard Test Conditions (STC) for solar modules [28].

Additionally, due to the scattering of light in the atmosphere, there exists a further portion called diffuse radiation, which together with the direct one constitutes the global radiation [28]. In photovoltaic plants the radiation reflected from the ground is also considered, adding themselves to an overall radiation E_G on the PV modules (see Figure 34) [28].

$$E_G = E_{G_{direct}} + E_{G_{diffuse}} [W/m^2] \text{ (Eq. 3)}$$

$$E_{total} = E_G + E_{G_{refl}} [W/m^2] \text{ (Eq. 4)}$$

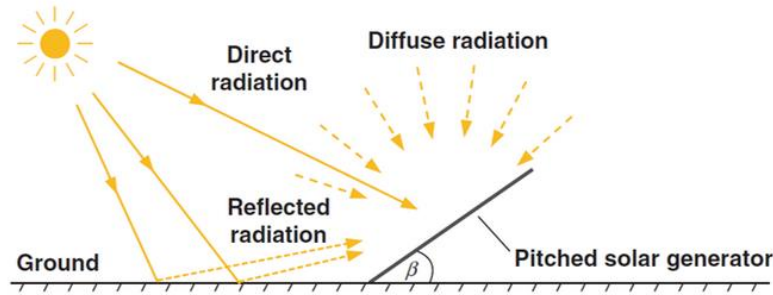


Figure 34: Direct, diffuse and reflected radiation in a solar generator [28]

In order to calculate the direct radiation taken up by a solar generator tilted by the angle β , the optical power P_{opt} of the impinging radiation is considered, which is equal in both $A_{Vertical}$ and A_H surfaces shown in the left sketch of the Figure 35 [28]:

$$P_{opt} = E_{H_{direct}} \cdot A_H = E_{V_{direct}} \cdot A_{Vertical} [W] \text{ (Eq. 5)}$$

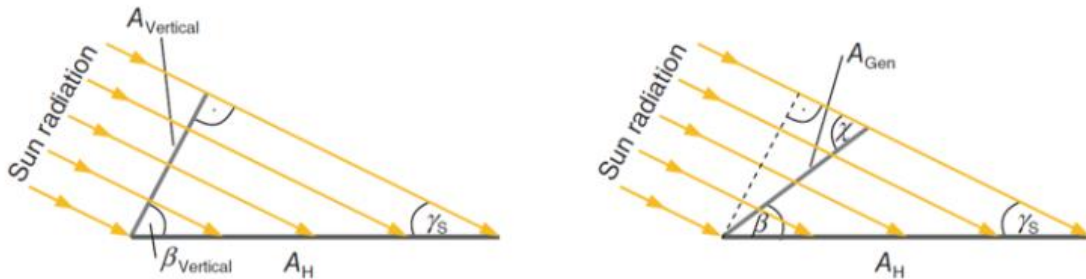


Figure 35: Influence of the solar generator tilt on direct radiation [28]

The relation between these two surfaces, as well as the relation between the vertical surface and the generator's surface A_G , are given by the following trigonometric equations:

$$A_{Vertical} = A_H \cdot \sin \gamma_s \text{ (Eq. 6)}$$

$$A_{Vertical} = A_{Gen} \cdot \sin \chi \text{ (Eq. 7)}$$

The complementary angle χ , for its part, is the result of summing the angles of the triangles considered in the right sketch of the Figure 35 [28]:

$$\chi = \gamma_s + \beta \text{ (Eq. 8)}$$

Thus, using the equations 5-8, the direct radiation impinging the generator's surface can be derived [28]:

$$E_{G_{direct}} = E_{H_{direct}} \cdot \frac{\sin(\gamma_s + \beta)}{\sin \gamma_s} [W/m^2] \text{ (Eq. 9)}$$

With regard to the diffuse radiation, a constant radiation in the whole sky is considered (the isotropic assumption), by which the general expression of the diffuse radiation takes the following form [28]:

$$E_{G_{diffuse}} = E_{H_{diffuse}} \cdot \frac{1}{2} \cdot (1 + \cos \beta) [W/m^2] \text{ (Eq. 10)}$$

Finally, reflected radiation depends on the reflection factor of different materials, which is estimated by the albedo value ALB . If the ground is not known, a standard value of $ALB = 0.2$ is taken. The same as the previous case, an isotropic assumption is made, so that the reflected radiation can be calculated as follows [28]:

$$E_{G_{refl}} = E_G \cdot \frac{1}{2} \cdot (1 - \cos \beta) \cdot ALB [W/m^2] \text{ (Eq. 11)}$$

Estimations of the yield of a photovoltaic plant are usually based on the year's global horizontal irradiation of a certain site $H [kWh/m^2 \cdot a]$, which is based on many years of measurements. However, the Model of Sun full hours is most commonly used to show the energy expected to be generated during a year. According to this, generation is carried out with the maximum radiation $E = E_{STC} = 1000 W/m^2$, so that the yield of a site is expressed in hours [28]:

$$\text{Number of full load hours} = \frac{H}{E_{STC}} [h] \text{ (Eq. 12)}$$

Finally, Figure 36 shows the Sun's azimuth α_s and solar altitude γ_s , which are used for depicting the displacement of the Sun from the south. Positive values show western deviations, whereas the negative ones show eastern displacements [28].

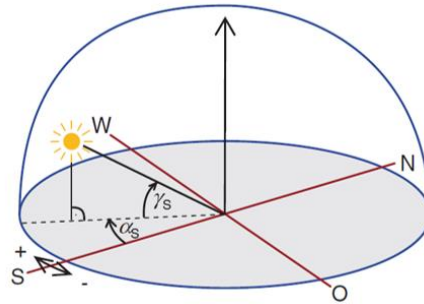


Figure 36: Calculation of the Sun's position with the dimension of solar altitude and Sun's azimuth [28]

In order to calculate these two variables and know the position of the sun each day of the year, it is necessary to calculate the Sun declination δ , as well as the local solar time LCS . Due to the tilt of the Earth, the Sun declination takes different values over the year. This is understood to be the respective tilt of the Earth's axis in the direction of the Sun, and it can be calculated knowing the day number N by the approximate equation of Cooper:

$$\delta = 23.45 \cdot \sin \left(2\pi \cdot \frac{284 + N}{365} \right) [^\circ] \text{ (Eq. 13)}$$

Figure 37 shows the evolution of Sun declination over the year, which varies from $\delta = -23.45^\circ$ in 21 December to $\delta = 23.45^\circ$ in 21 June.

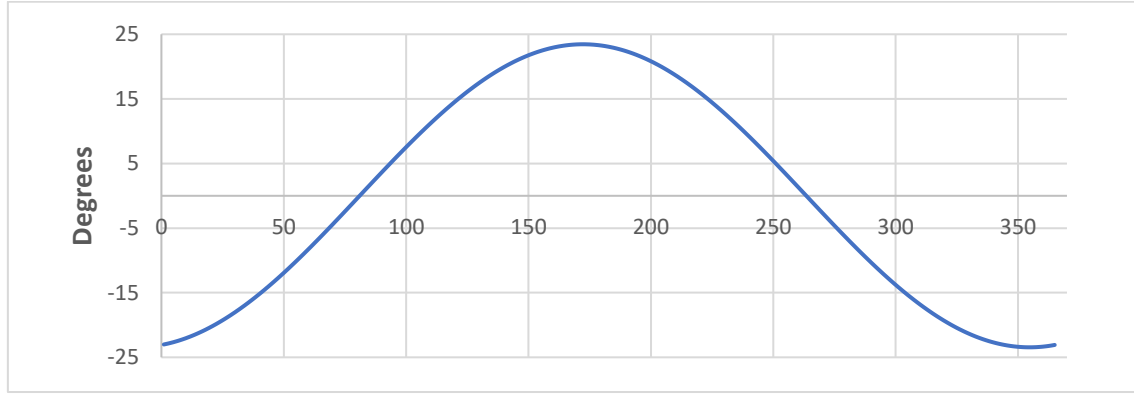


Figure 37: Sun declination over the year

The Local Solar Time, for its part, is the time in which at noon the Sun is exactly in the south, reaching its highest point of the day. In order to make a relation between LST and the Standard Time ST the Coordinated Universal Time UTC needs to be calculated, which is referenced to the zero meridian at Greenwich. The difference between both times is determined using the respective longitude Λ and the approximation that 1h corresponds to 15° [28]:

$$UTC = LST - 1h \cdot \frac{\Lambda}{15^\circ} \quad (Eq. 14)$$

Finally, the relation between ST and UTC is given by the deviation of the Time Zone TZ compared to UTC :

$$ST = UTC + TZ \quad (Eq. 15)$$

However, in order to abbreviate the expressions that describe the position of the Sun, hour angle ω is introduced, which calculates the local solar time into the respective rotation position of the Earth [28]:

$$\omega = (LST - 12) \cdot 15^\circ \quad (Eq. 16)$$

Hence, the position of the Sun can be determined from the latitude φ , the Sun declination δ and the hour angle ω [28]:

$$\sin(\gamma_s) = \sin(\varphi) \cdot \sin(\delta) + \cos(\varphi) \cdot \cos(\delta) \cdot \cos(\omega) \quad (Eq. 17)$$

$$\sin(\alpha_s) = \frac{\cos(\delta) \cdot \sin(\omega)}{\cos(\gamma_s)} \quad (Eq. 18)$$

2.3.2.- Solar cells

The basis of photovoltaic power generation is the solar cell, an asymmetrically doped p-n junction by which photons are absorbed, generating free electron-hole pairs. These particles are separated from the field of the space charge region and moved to the contacts, which are small metal strips that transport the electrons to the current collector rail (see Figure 38) [28].

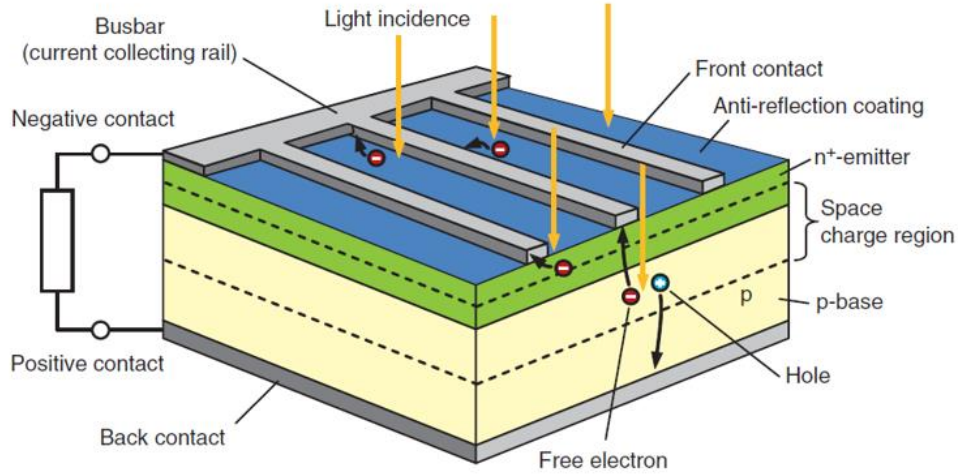


Figure 38: Typical solar cell [28]

It is assumed that every absorbed photon leads to an electron-hole pair, so that the generated photocurrent I_{ph} is proportional to the irradiance E_{total} [28]:

$$I_{ph} = \text{const} \cdot E_{total} [A] \text{ (Eq. 19)}$$

The characteristic curve equation of a solar cell is as follows [28]:

$$I = I_{ph} - I_D = I_{ph} - I_S \cdot \left(e^{\frac{V}{V_T}} - 1 \right) [A] \text{ (Eq. 20)}$$

Where,

- I : current flowing from the energy source to the load.
- V : voltage measured at the energy source.
- I_D : diffusion current of the diode.
- I_S : saturation current of the diode.
- V_T : thermal voltage.

Individual points of the characteristic curve are considered in order to determine the most important parameters of solar cells, which are the short circuit current I_{SC} , the open circuit voltage V_{OC} and the maximum power point MPP . Furthermore, nominal power P_N , current I_N and voltage V_N are also included in data sheets of solar modules (see Figure 39) [28].

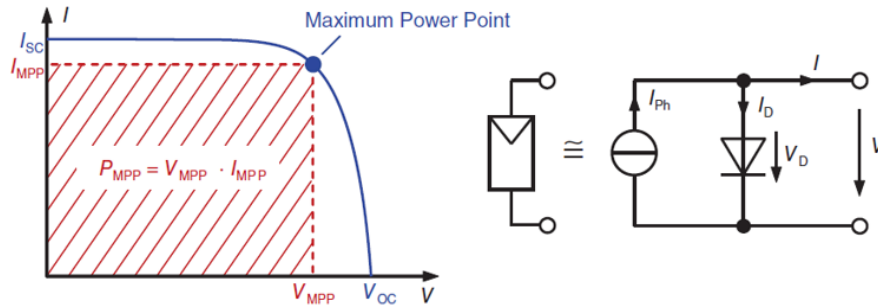


Figure 39: Characteristic curve of a solar cell and its associated simplified equivalent circuit [28]

The short circuit current represents the current delivered by the solar cells when they are short circuited at their connections, that is, $V = 0$ [28]:

$$I_{SC} = I(V = 0) = I_{ph} - I_S \cdot (e^0 - 1) = I_{ph} [A] \quad (Eq. 21)$$

The open circuit voltage, on the other hand, is the voltage delivered by the solar cells when the current is zero. In this case [28]:

$$V_{OC} = V(I = 0) = V_T \cdot \ln\left(\frac{I_{SC}}{I_S} + 1\right) \simeq V_T \cdot \ln\left(\frac{I_{SC}}{I_S}\right) [V] \quad (Eq. 22)$$

The maximum power point is the operating point at which the maximum power P_{MPP} is provided, and it is equal to the maximum area corresponding to the surface $V \cdot I$. The current and voltage values associated with MPP are called I_{MPP} and V_{MPP} [28].

The fill factor FF describes the relationship of MPP power and the product from open circuit voltage and short circuit current, and it is a measure for the quality of a cell [28]:

$$FF = \frac{V_{MPP} \cdot I_{MPP}}{V_{OC} \cdot I_{SC}} \quad (Eq. 23)$$

Finally, the efficiency η of a solar cell describes the fraction of the optical power P_{op} incident on the cell that is output as electrical energy P_{MPP} [28]:

$$\eta = \frac{P_{MPP}}{P_{op}} = \frac{FF \cdot V_{OC} \cdot I_{SC}}{E \cdot A} \quad (Eq. 24)$$

Taking into account the equations 21 and 22, therefore, it can be deduced that the short circuit current increases linearly with the irradiance, whereas the open circuit voltage alters little (see Figure 40) [28].

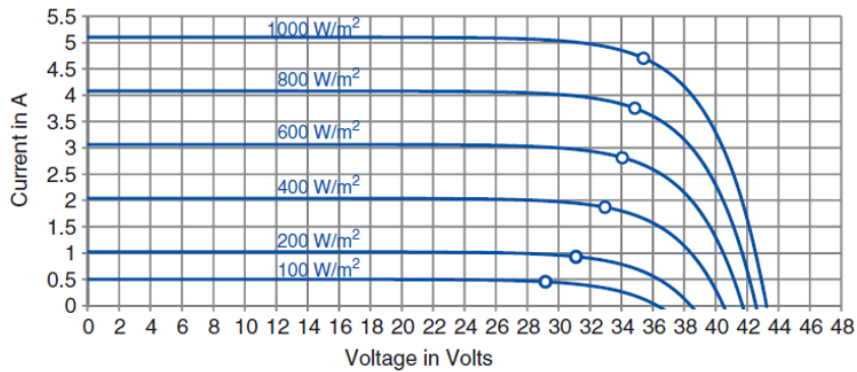


Figure 40: Variation of irradiance at a constant temperature [28]

Conversely, knowing that the thermal voltage V_T is linearly proportional to the temperature, it can be derived from equation 21 and 22 that the open circuit voltage changes linearly with the temperature, whereas the influence of this in the short circuit current is insignificant (see Figure 41) [28].

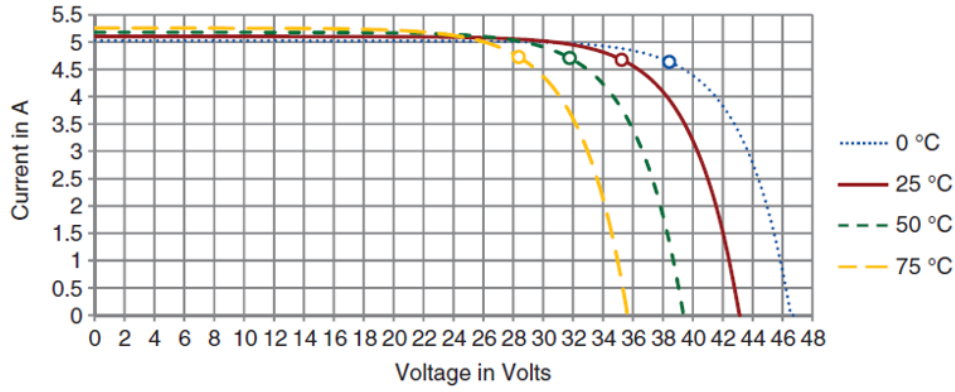


Figure 41: Variation of temperature at a constant irradiance [28]

In order to estimate the self-heating of a particular module, nominal operating cell temperature $NOCT$ is given in data sheets. This is defined as the temperature achieved by the cell in the following conditions [28]:

- Irradiance $E = E_{NOCT} = 800 \text{ W/m}^2$.
- Ambient temperature $\vartheta_a = 20 \text{ }^\circ\text{C}$.
- Wind velocity $v = 1 \text{ m/s}$.

If it is assumed that the temperature increase against the ambient temperature is proportional to the irradiance, then the expected cell temperature ϑ_{cell} can be approximately calculated as follows [28]:

$$\vartheta_{cell} = \vartheta_a + (NOCT - 20^\circ\text{C}) \cdot \frac{E_{total}}{E_{NOCT}} \quad (\text{Eq. 25})$$

In order to consider the effect of the cell temperature in the main variables of the module (I_{SC} , V_{OC} and P_{MPP}), data sheets also provide temperature coefficients for each of them: $TC(I_{SC})$, $TC(V_{OC})$ and $TC(P_{MPP})$. Thus, for a given cell temperature ϑ_{cell} and temperature coefficient $TC(P_{MPP})$, the actual power can be determined [28]:

$$P = P_{STC} \cdot [1 + TC(P_{MPP}) \cdot (\vartheta_{cell} - 25^\circ\text{C})] \quad [\text{W}] \quad (\text{Eq. 26})$$

2.3.3.- Solar generators

The open circuit voltage of each cell is $V_{OC} = 0.6 \text{ V}$. Therefore, in order to achieve higher voltages, many cells are connected in a module in series. Figure 42 shows the influence of series connection with an example of three-cell module: the current remains the same in all the cells, whereas the overall voltage is made up of the sum of the voltage of each cell [28]:

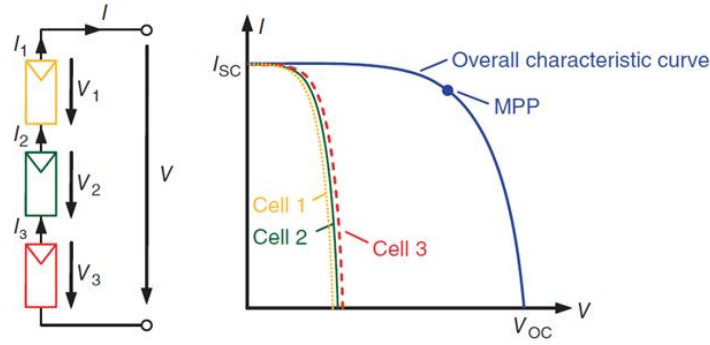


Figure 42: Series connection of solar cells [1]

Modern modules are constituted by a number of 36, 48, 60 or 72 cells connected in series, achieving voltages of between 18 V and 36 V. The general expressions for the current and the voltage of the module are as follows [28]:

$$V = \sum_{i=1}^n V_i, \quad \text{with } n = \text{number of cells (Eq. 27)}$$

$$I = I_i, \forall i \text{ (Eq. 28)}$$

When one of the cells is partly shaded, however, the current is almost completely determined by it, that is, $I \approx I_1$, reducing thus the overall MPP power achieved by the module. In order to avoid this, bypass diodes are connected anti-parallel to solar cells, so that they conduct the current when the cell is not operational [28]. Due to the heat created by the diodes, nevertheless, only a few bypass diodes are used in the solar modules, typically one for 12, 18 or 34 cells [28].

A solar generator is constituted by parallel-connected strings, each of which consisting of a row of modules connected in series. A string diode is also included in each string, in order to avoid a reverse current through the defective string if a short circuit or an earth fault occurs. Due to their voltage drop, however, string diodes are being replaced nowadays by string fuses [28]. Figure 43 shows the connection of a bypass diode for each module, as well as the connection of a string diode for each string.

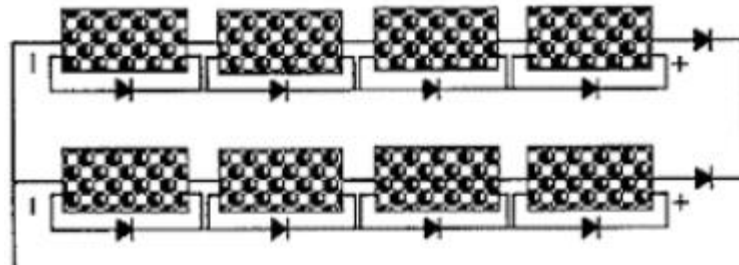


Figure 43: Series and parallel connection of a solar generator [29]

2.3.4.- Inverters

Besides the solar modules, the inverter is the most important part of a photovoltaic system connected to the grid. It takes care of converting the direct current generated in the modules into a sinusoidal-form alternating current, feeding it synchronously with the grid frequency.

Moreover, it takes into account partial and peak loads so as to achieve a high degree of efficiency and carries out the MPP tracking as well [28].

The Figure 44 shows the most common arrangement of a plan connected to the grid. The individual strings are connected in parallel by means of a generator connection box, and the power generated by the solar modules is fed into the grid via a central inverter [28].

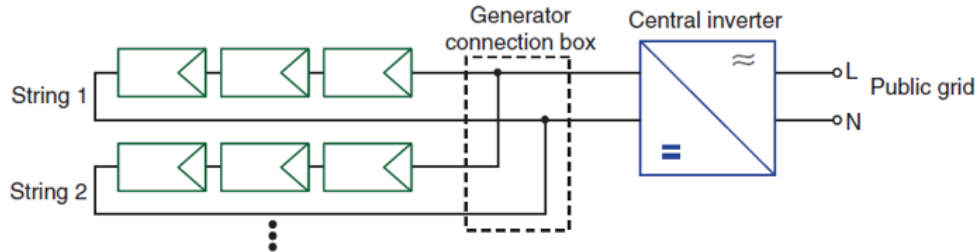


Figure 44: Arrangement of the photovoltaic system connected to the grid [28]

3.- FORECASTS OF THE SPANISH ELECTRICITY MARKET

3.1.- Electricity generation mix

3.1.1.- Forecasts for different technologies

Based on the expected increase in both GDP and electrification of the demand necessary for the decarbonisation process, an average increase of between 1% and 2.4% per year is expected for the electricity demand until 2030 (see Figure 45) [25]. In the present work, the same growth rate will be considered for the period 2030-2050 [25]. The maximum value of this growth constitutes the scenario of greater electrification and GDP growth (1.7% per year), whereas the minimum one is a result of more conservative forecasts (less electrification and an average GDP growth of 0.9% per year [25]).

In order to simplify the analysis, an average growth rate of 1.7% will be considered, as a result of the arithmetic mean of both scenarios. According to this assumption, electricity demand in Spain should reach approximately 470 TWh in 2050, compared to the current 280 TWh.

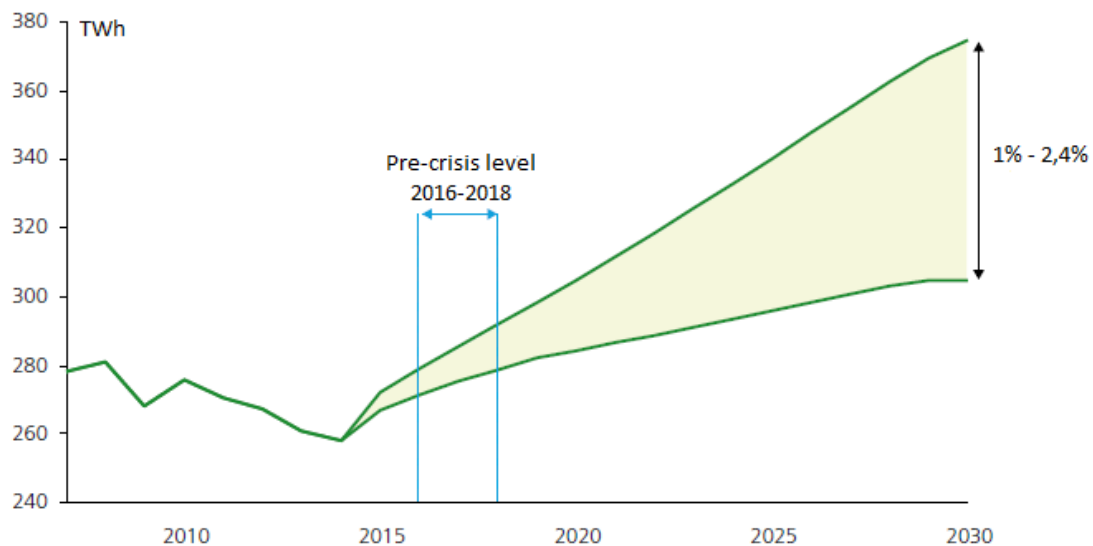


Figure 45: Evolution of electricity demand up to 2030 in Spain [25]

The forecasts that have been carried out in this work for the future power generation structure in Spain start from the basis that the objectives set by the EU in terms of environmental policies will be met. These aim, as already mentioned above, to reach a low-carbon economy in 2050, whose emissions would constitute a reduction of between 80% and 95% compared to 1990 levels [25]. This means that participation of renewable energies should increase progressively until reaching, in 2050, a share of between 90% and 100% in the electric mix [25]. In the present work a reference value of 90% will be taken into account, which means that by 2030, 55% of electricity generation should come from renewable sources.

In terms of technologies, although hydroelectric power has been historically growing, in recent decades its importance in the generation structure has been diminished, mainly due to the irruption of other renewable energies in the electric mix. However, given its relevance as a reliable and, above all, non-emitting generation source, current hydroelectric plants are

expected to remain operational during the period 2020-2050. As a result of the saturation of the hydraulic potential in Spain, nevertheless, the installation of new capacity during the period 2020-2050 will not likely exceed the 8 GW of power [25]. Therefore, it will be considered that this capacity will be installed progressively throughout the said period, 5 GW in conventional hydro and 3 GW in pumping power plants.

Regarding wind and solar PV technologies, due to their increasing reduction in their electricity generation costs, all forecasts point to both being the protagonists of the energy transition in the future. Thus, in order to simplify the analysis, these two technologies, together with hydroelectric power, will be considered responsible for increasing the participation of renewables in the generator park. On account of that, both the capacity of thermal solar technology and the rest of minority renewables will be considered as constant during the period 2020-2050.

Moreover, upon evaluating the weight of both wind and solar PV in the new power to be installed, a correlation has been assumed between the future implementation of these technologies and the expected evolution of their generation costs. According to this, between 2020 and 2030 wind is expected to be the predominant technology, given its lower generation costs, whereas from 2030 solar PV would become the most economical renewable source, increasing therefore its market share (see Figure 46). However, due to the small difference between their respective costs, it will be assumed that the new installed power, both in wind and solar PV, will be equal during the period 2020-2050.

Solar's Price Plunge

Cost per megawatt hour, in 2016 dollars. Solar power is projected to become cheaper than coal in 2024 and wind in 2029.

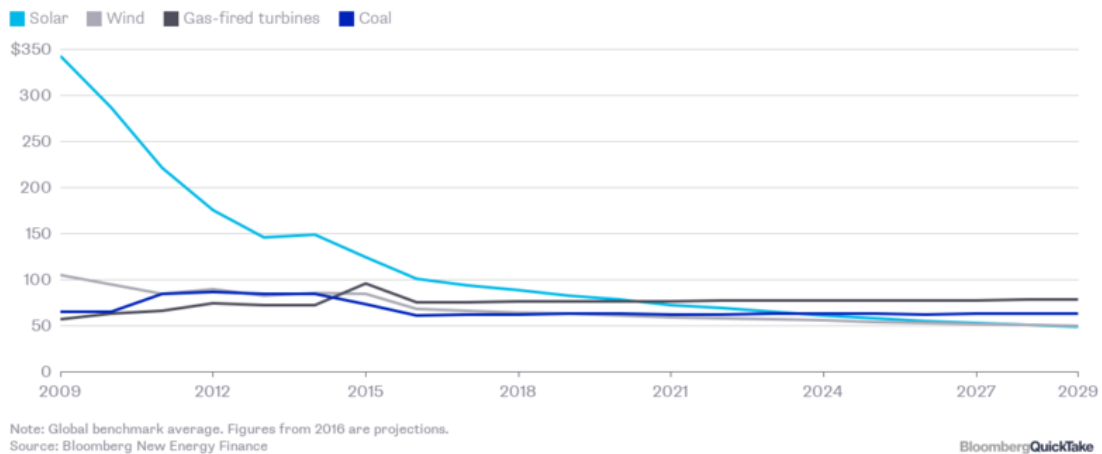


Figure 46: Generation costs for different technologies [32]

Apart from that, this increase in non-manageable electricity generation will require, in turn, a relevant capacity of support and flexibility [25]. By 2050, it is expected that this capacity will be complemented with other options of firm and flexible capacity, such as international interconnections, demand management and new storage technologies. Given the uncertainty about the time necessary for the development of these alternatives, however, a conservative scenario has been considered in which the said support will be entirely provided by the thermal park and the nuclear power plants [25].

Within the thermal park, the future of conventional coal-fired power plants is very jeopardised after the Paris Agreement, whose environmental objectives are incompatible with the emissions generated by this technology. What is more, in the proposal of the new Regulation of the European Parliament and of the Council on the internal electricity market, it is proposed to remove capacity mechanisms for plants with specific emissions higher than $550 \text{ g CO}_2/\text{kWh}$, which would result in the closure of a large part of the current coal plants [33].

Likewise, many of the European powers (Germany, France and United Kingdom, among others) have already considered closure measures for all their coal-fired power plants between 2025 and 2030 [31]. In this context, there is a high probability that Spain will follow the same steps. Consequently, a progressive closure of coal thermal power plants will be assumed between 2018 and 2030, the year after which this technology will disappear from the generation mix.

Taking into account, on the other hand, the decrease in the installed capacity of fuel oil thermal power plants in the recent years (see Figure 47) and considering as well the greater specific emissions of the said fuel compared to natural gas, it is also assumed a progressive closure of fuel oil power plants between 2018 and 2030. As a result, the thermal gap left by the coal and fuel oil plants will be progressively occupied by CCGT power plants. Indeed, due to their low CO_2 emissions compared to the others, CCGTs will represent the necessary backup technology for the energy transition to be made over the coming years.

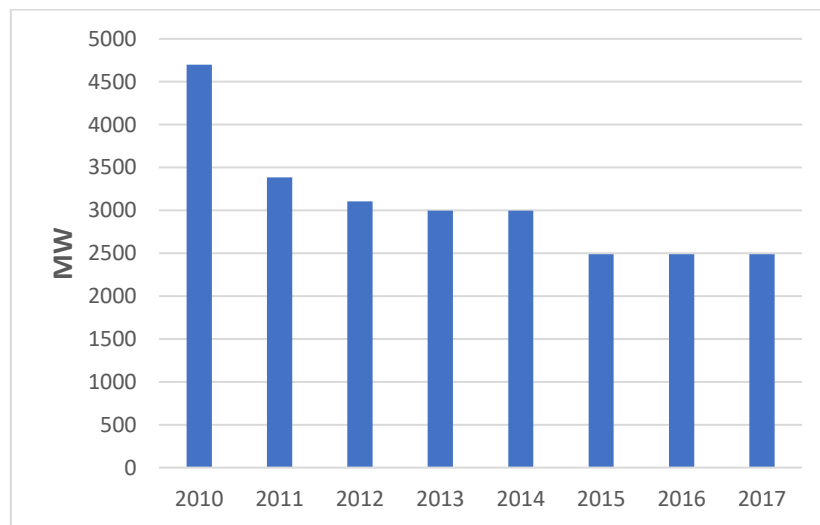


Figure 47: Evolution of capacity in Fuel/gas, 2010-2017 [20]

Finally, taking into account the objectives in CO_2 emissions, on the one hand, and the progressive closure of a considerable part of the thermal park, on the other, nuclear energy could turn out to be a key technology for reducing emissions, as well as for the security of supply of the Spanish electricity system [25]. Despite the fact that the five nuclear power plants currently operating are scheduled to close between 2020 and 2030, the possibility of extending their lifetime to 60 years is currently being negotiated, so that they could remain operational until 2050, approximately. Given the current situation of the Spanish electricity sector, it is very likely that the said extension will take place. Thus, the maintenance of the current 7117 MW of nuclear capacity will be assumed until the year 2050.

3.1.2.- Installation of new capacity

As previously mentioned, the sum of the hydraulic capacity to be installed between 2020 and 2050 amounts to 8 GW, for which a progressive and linear installation is assumed during the period. For coal and fuel thermal power plants, on the other hand, a linear and progressive closure is assumed until 2030, the year after which they will be completely removed from the Spanish generator park. In the case of nuclear power plants, as well as for other technologies, the installed capacity is going to remain constant at 7117 MW and 7345 MW, respectively, until 2050.

In order to be able to estimate approximately the electricity generation by each technology based on their installed capacity, load factor f_l of each technology has been determined as follows:

$$f_{l_i} = \frac{G_i \cdot 1000}{24 \cdot 365 \cdot P_i} \cdot 100 [\%] \text{ (Eq. 29)}$$

Where,

- G_i [GWh]: electricity generated by technology i .
- P_i [MW]: installed capacity of technology i .

Calculations have been carried out based on monthly electricity generation and installed capacity of each technology during the last 8 years, and both average annual load factor and average monthly load factor have been determined. Figure 48 shows the average monthly load factors of the technologies which show a clear seasonality, owing to their dependence on weather conditions throughout the year:

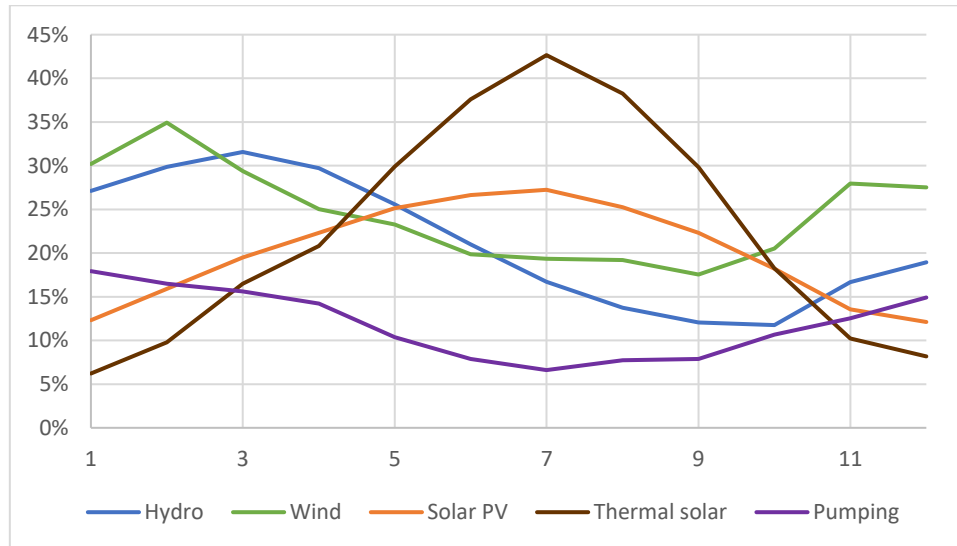


Figure 48: Average monthly load factor for technologies dependent on climate conditions [20]

On the contrary, the load factor of nuclear power plants is relatively constant throughout the year, around an average value of $f_{l_{nuclear}} = 85.3\%$, given their function as base power plants. The thermal park, for its part, responds to the fluctuations of renewable energies, meeting the demand in the absence of them.

As a result of the progressive closure of thermal coal and fuel oil power plants, nevertheless, it will be considered a constant load factor for both of them, so that the gap left by renewable energies will be covered by CCGTs. Therefore, load factors for coal and fuel oil power plants will take values equal to their respective annual average of the last 8 years, $f_{l_{coal}} = 44.6\%$ and $f_{l_{fueloil}} = 26.6\%$, whereas CCGT's load factor will depend, each month, on the variable contribution of renewables in the generation structure. For the latter, average monthly load factors will be taken into account, so that electricity generation will vary throughout the year, despite the fact that the installed capacity is the same (see Figure 48).

Lastly, the rest of technologies show a relatively constant load factor around $f_{l_{others}} = 50.1\%$, so this is the value which will be considered for them. Table 1 includes the average annual load factors of the different technologies, except for CCGT's load factor, which will be calculated later:

Technology	$f_{l_{average}}$
Nuclear	85.3%
Coal	44.6%
Fuel oil	26.6%
CCGT	-
Hydro	21.2%
Wind	24.6%
Solar PV	20%
Thermal solar	22.4%
Pumping	12%
Others	50.1%

Table 1: Annual average load factor for different technologies [20]

For the calculation of the annual capacity to be installed in wind and solar PV, annual renewable generation has been determined during 2020-2050. This will increase year by year based on the growth of its share in the generator mix in order to meet the environmental requirements:

$$G_{RE_i} = D_i \cdot RE_i \text{ [GWh]} \text{ (Eq. 30)}$$

Where,

- G_{RE_i} [GWh]: electricity generation by renewable source in year i .
- D_i [GWh]: electricity demand in year i .
- RE_i [%]: percentage of the total renewable sources in the generation structure in the year i .

The generation $G_{required_i}$ required each year i , therefore, for wind and solar PV, will be the one that is necessary after subtracting the contributions of the rest of renewable technologies:

$$G_{required_i} = G_{RE_i} - (G_{hydro_i} + G_{thermosolar_i} + G_{pumping_i}) \text{ [GWh]} \text{ (Eq. 31)}$$

Where,

- G_{RE_i} [GWh]: electricity generation by renewable sources in the year i .
- G_{hydro_i} [GWh]: hydraulic generation in the year i .
- $G_{thermosolar_i}$ [GWh]: thermal solar generation in the year i .
- $G_{pumping_i}$ [GWh]: pumping turbine generation in the year i .

In order to calculate the energy generated in the year i , G_{new_i} , by means of new capacity in wind and solar PV, it is necessary to subtract the energy generated by the capacity already installed (year $i - 1$) in both technologies, $G_{wind_{i-1}}$ and $G_{PV_{i-1}}$, respectively, so that it is possible to determine the capacity that is necessary to install each year i in order to meet both the increase in demand and the growth in the share of renewable energies:

$$G_{wind_{i-1}} = \frac{24 \cdot 365 \cdot f_{l_{wind}} \cdot P_{wind_{i-1}}}{1000} \text{ [GWh]} \text{ (Eq. 32)}$$

$$G_{PV_{i-1}} = \frac{24 \cdot 365 \cdot f_{l_{PV}} \cdot P_{PV_{i-1}}}{1000} \text{ [GWh]} \text{ (Eq. 33)}$$

$$G_{new_i} = G_{required_i} - G_{wind_{i-1}} - G_{PV_{i-1}} \text{ [GWh]} \text{ (Eq. 34)}$$

Where,

- $P_{wind_{i-1}}$ [MW]: installed wind capacity in the year $i - 1$.
- $P_{PV_{i-1}}$ [MW]: installed solar PV capacity in the year $i - 1$.
- $f_{l_{wind}}$ [%]: Average annual load factor of wind technology.
- $f_{l_{PV}}$ [%]: Average annual load factor of solar PV technology.

Finally, given that the same annual installation has been assumed for both wind and solar PV, the new capacity to be installed ΔP_i each year i for each technology is determined as follows:

$$\Delta P_i = \Delta P_{wind_i} = \Delta P_{PV_i} = \frac{1000 \cdot G_{new_i}}{24 \cdot 365 \cdot (f_{l_{wind}} + f_{l_{PV}})} \text{ [MW]} \text{ (Eq. 35)}$$

Equation 35 allows to determine the new capacity of wind and solar PV that will be required each year, so as to meet the incremental share of renewables in the generation structure over the period 2020-2050.

Once the installed capacity of these is known, therefore, the only unknown factor in the future generator park is the backup capacity in CCGTs that would ensure the electrical supply of the system. For this, it is necessary to calculate the coverage index of the system, which is defined as the ratio between the available capacity P_{av} in the system and the peak power P_{peak} required by the demand. In this project, a coverage index of $ci = 1.1$ will be considered, a reference value that, in principle, ensures the supply of the demand [18].

$$ci = \frac{P_{av}}{P_{peak}} = 1.1 \text{ (Eq. 36)}$$

With the aim of estimating the peak demand based on the expected demand of electricity for the period 2020-2050, the ratio between peak power P_{peak} and annual demand D of the last decade has been analyzed:

$$r = \frac{P_{peak}}{D} [GW/TWh] (Eq. 37)$$

The evolution of this ratio is shown in the Figure 49. Despite undergoing certain deviations, the ratio takes values very close to an average of $r = 0.1546 \text{ GW/TWh}$, as a result of which it will be taken as a reference in order to calculate the expected peak power P_{peak_i} for each year i . Nevertheless, due to demand response systems and the gradual improvements of the international interconnections, this ratio is expected to decrease by 4% in 2030 and 8% in 2050 [18].

$$P_{peak_i} = r \cdot D_i [MW] (Eq. 38)$$

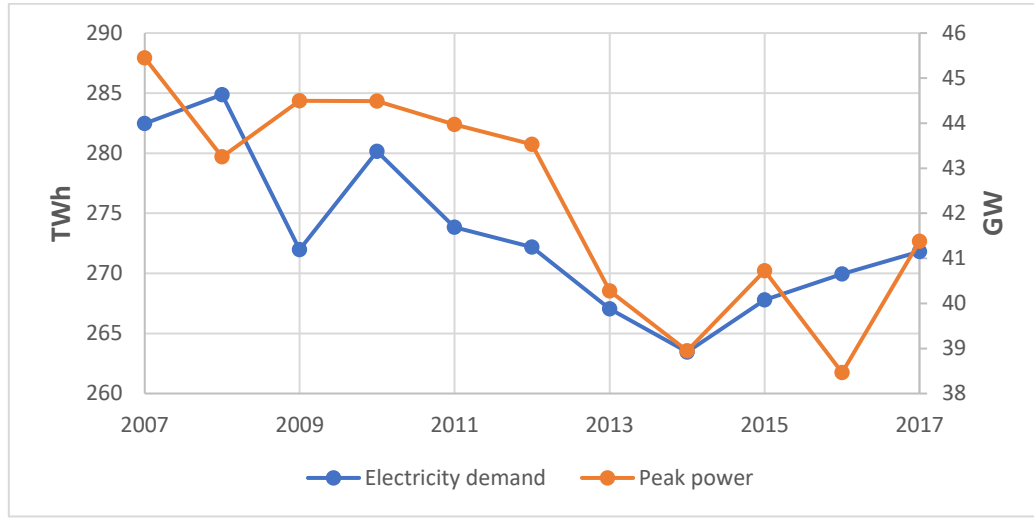


Figure 49: Relation between electricity demand (left) and peak power (right)

Once the peak power is known for each year during the period 2020-2050, the available power P_{av_i} required each year i can be determined with the Equation 36. This is understood to be the capacity that can be considered as firm for a predetermined confidence interval [18]. The results are shown in Figure 50, which includes the increase of electricity demand, the peak power correlated with it and the available capacity that should exist over the period 2020-2050. In 2050, a peak demand of 67 GW is expected, compared to the current 43 GW, whereas the required available power will raise from 47 GW in 2018 to 74 GW in 2050.

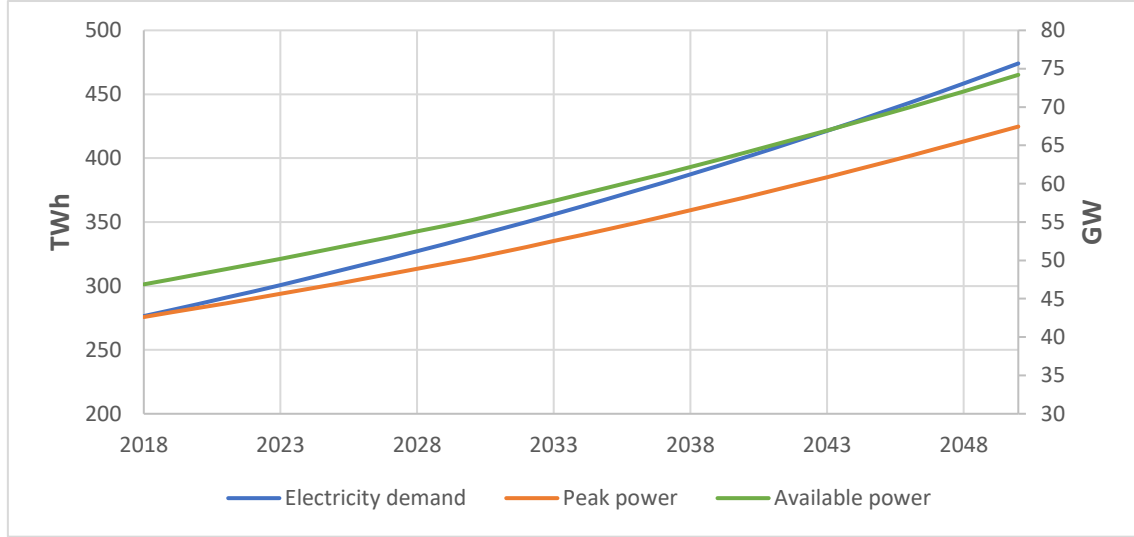


Figure 50: Electricity demand (left), peak power (right) and available power (right) in the period 2018-2050

Hence, the capacity to be installed each year in CCGT will be that which ensures the said availability. However, since each generation technology presents a different availability, availability factors f_{av} needs to be considered for each of them. For the calculation of these factors, different variables must be taken into account, such as the programmed availability of the equipment, fuel stocks, maintenance stops or breakdowns. In the case of renewables, these factors are statistically determined according to the availability of natural resources [18].

Table 2 the availability factor f_{av} of each technology for a 95% confidence interval. These factors represent, as already said, the fraction of the capacity of each technology that can be considered as firm for the said interval [18].

Technology	f_{av}
Nuclear	91%
Coal	91%
Fuel oil	78%
CCGT	93%
Hydro	38%
Wind	7%
Solar PV	0%
Thermal solar	20%
Pumping	90%
Others	50%

Table 2: Availability factor for different electricity generation technologies [18]

Once these factors have been obtained, and also knowing the available capacity that ensures electrical supply each year i , the required capacity of CCGT for each year P_{CCGT_i} can be obtained:

$$P_{CCGT_i} = \frac{1}{f_{avCCGT}} \cdot \left(P_{av} - \sum_{j=1}^{n-1} f_{avj} \cdot P_j \right)_i [GW] \text{ (Eq. 39)}$$

Where,

- P_j : installed capacity of technology j .
- f_{dj} : availability factor of technology j .
- P_{av} : required available capacity.
- f_{avCCGT} : availability factor of CCGT.
- n : number of technologies in the electricity generation mix.

3.1.3.- Results

The results obtained are shown in Figure 51, which includes the evolution of the installed capacity of the different generation technologies between 2020 and 2050. According to this, in order to achieve a renewable share of 90% by the year 2050, 2.6 GW per year should be installed in both wind and solar PV, which together with the 8 GW of hydro power (both conventional and pumping), would amount a total of 170 GW of new installed capacity during the period.

At the same time, it will be necessary to install 17,736 MW of CCGTs, which would be responsible for giving a flexible backup to the Spanish generator park. It should be noted that the need for new capacity in CCGT will not occur until 2027, as a result of the current overcapacity in this technology. Overall, together with the current 26,670 MW, the installed capacity in CCGTs should reach 45,406 MW by 2050.

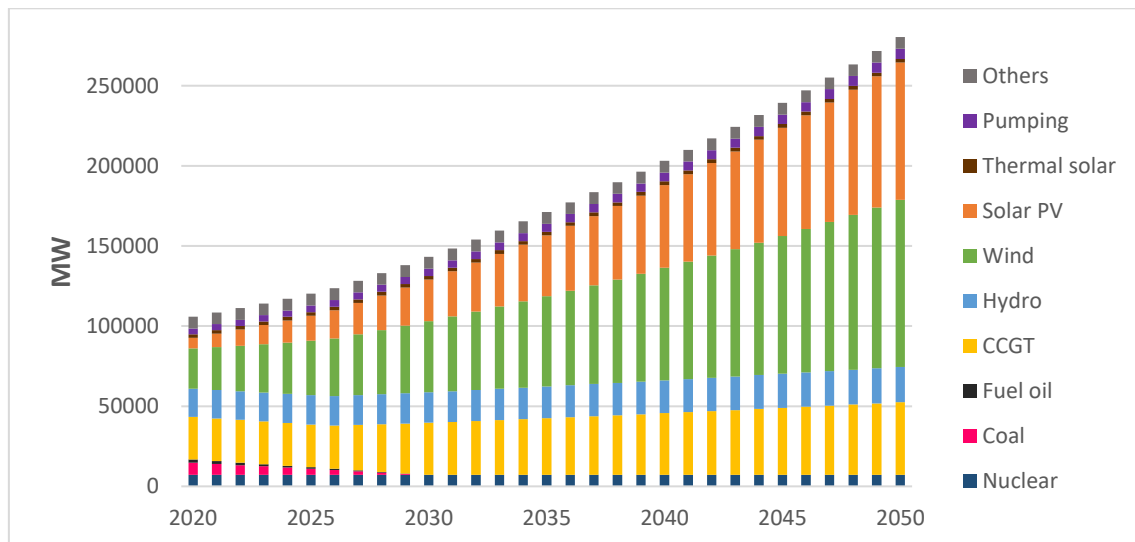


Figure 51: Evolution of installed capacity between 2020 and 2050

Overall, an increase of 165% is expected in installed capacity between 2020 and 2050, going from 106 GW to 280 GW in the said period. This increase contrasts with the lower electricity generation, 81% exactly, which is due to the reduced load factors of the main technologies installed during the period (wind and solar PV). This increase in electricity generation contrasts, in turn, with a lower increase of the electricity demand between 2020 and 2050, 66% exactly.

This over-generation (9% higher than demand in 2050) is a result of the high share of renewables in the generator mix, on the one hand, and the maintenance of the nuclear park throughout the period. In order to balance generation and demand, a progressive closure of the

nuclear power plants between 2020 and 2050 should be assumed, a hypothesis that has not been carried out in the present work. Figure 52 shows the evolution of electricity generation by different technologies, as well as the evolution of demand over the period 2020-2050.

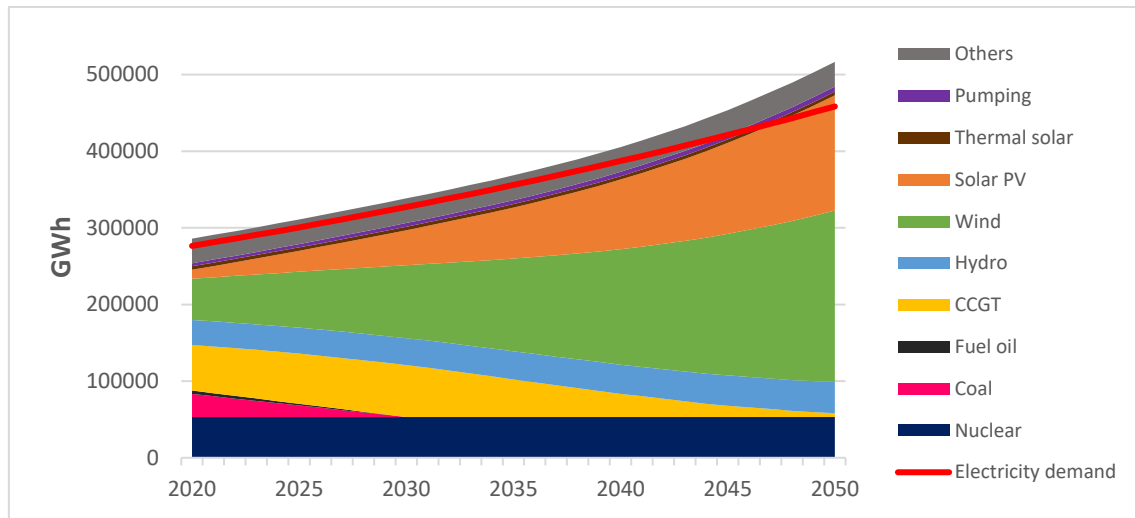


Figure 52: Evolution of electricity generation and demand between 2020 and 2050

Figure 53, on the other hand, shows the evolution of the share of each technology in the electrical mix throughout the said period. In 2050, renewable generation represents 90% of electricity demand, with a share of 82% in the electricity generation mix. Among the different renewables, wind accounts for 43% of the generation, followed by solar PV (29%) and hydro (8%). Nuclear generation, for its part, goes from 19% in 2020 to 10% in 2050.

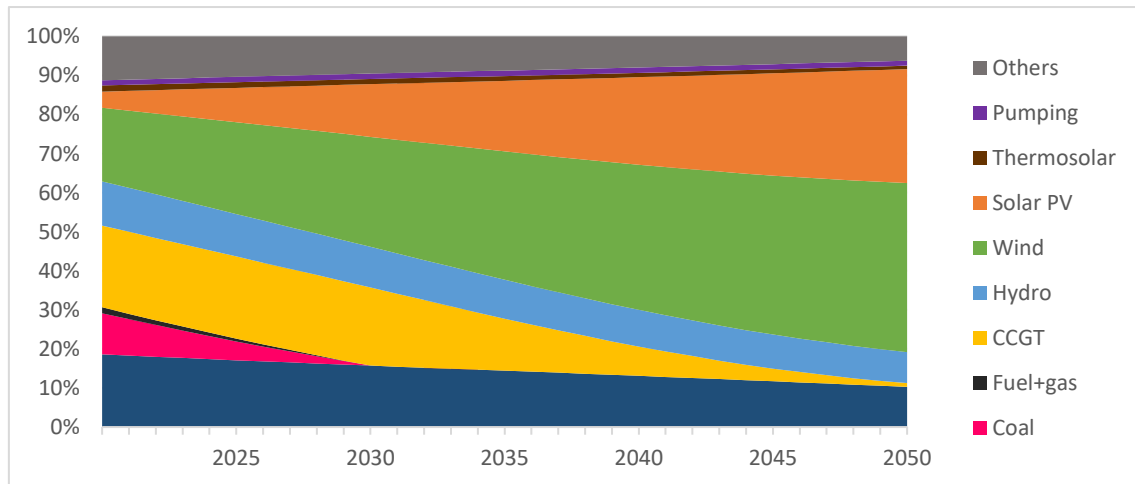


Figure 53: Evolution of the electricity generation structure between 2020 and 2050

Finally, it is worth highlighting the reduction in electricity generation of CCGTs, which goes from 21% of the total generation in 2020 to 1% in 2050. This decrease (92% between 2020 and 2050) contrast with the increasingly installed capacity in CCGTs over the period, which is actually necessary for the security of electricity supply. As a result, the load factor of this technology undergoes a remarkable decrease between 2020 and 2050. Figure 54 shows the evolution of the load factor of CCGTs during this period. There, can be seen the monthly fluctuations undergone

by electricity generated by CCGTs, which are a result of the fluctuations of renewable generation.

Regarding the evolution of the average annual load factor, it can be seen how it increases between 2020 and 2026, owing to the progressive closure of coal and fuel oil power plants, whereas thereafter it begins to decline, going from a factor of 28% in 2027 to 1% in 2050.

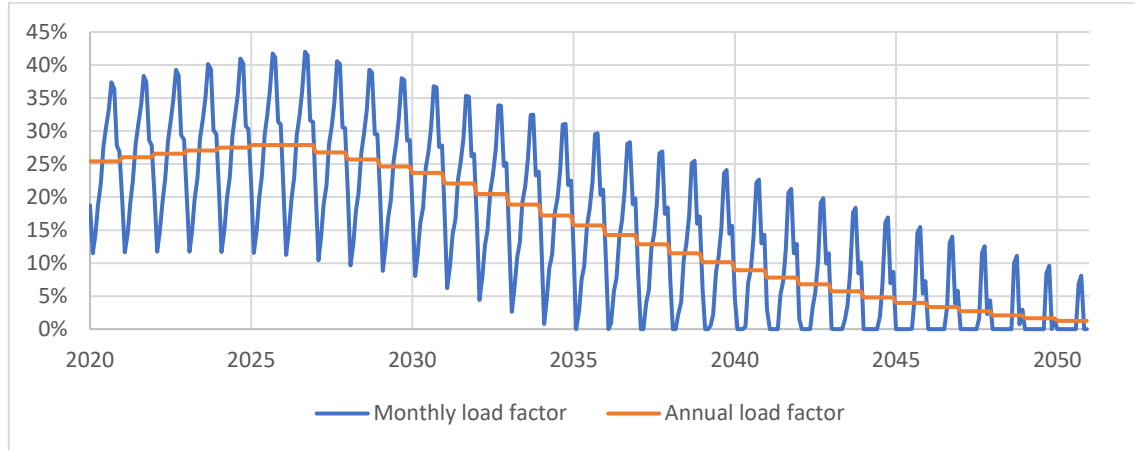


Figure 54: Evolution of load factor for CCGT between 2020 and 2050

3.2.- Price of the electricity in the daily market

3.2.1.- Costs of a power generation plant

Costs of a power generation plant cover both capital costs C_{cap} and operational costs C_{op} incurred over the lifetime of the plant. The former represents the initial investment necessary for the plant to enter its operational phase, whereas the latter are the expenses related to the operation of the plant.

Capital costs include different concepts, such as pre-development costs, construction costs and infrastructure costs. Operational costs, on the other hand, can be divided into fixed costs (not dependent on production) and variable costs (dependent on the amount of electricity generated by the plant). Among the different operational costs, it is worth highlighting both fixed and variable operation and maintenance (O&M) costs, the costs of the fuel used in the power generation process, as well as the costs related to CO_2 emission rights [30]. Despite the great variety of costs existing in both the development and operation of a power generation plant, in order to simplify the analysis only the following concepts will be considered:

Capital costs

- C_{pd} [€/kW]: pre-development costs of the project, present in the pre-development period of the power generation plant, which varies depending on the technology.
- C_c [€/kW]: construction costs of the project, present in the construction period of the plant, which varies depending on the technology.

Operational costs

- $C_{O\&M_f}$ [€/kW/year]: fixed O&M costs, present throughout the operational life of the plant, and independent of the amount of electricity generated by it.
- $C_{O\&M_v}$ [€/MWh]: variable O&M costs, dependent on the amount of electricity generated by the plant.
- C_{fuel} [€/MWh]: cost of the fuel, which will vary depending on the demand of the plant and, therefore, on the amount of electricity generated.
- C_{CO_2} [€/MWh]: costs related to the acquisition of CO_2 emission rights necessary for the activity of the plant, which will vary depending on the generated emissions and, therefore, will depend on the amount of electricity generated.

It should be noted that fuel costs and those related to CO_2 emission rights will depend on the existing prices in their respective markets, which fluctuate constantly over the time. On the contrary, the rest of the costs can be calculated based on the previous experience of power plants, as well as the expectations and assumptions about the learning rates of different technologies. Consequently, these estimations are subject to certain uncertainty that can cause considerable deviations between the estimated costs and those that are actually incurred in the development of the project [30].

Table 3 includes the costs associated with the main electricity generation technologies, except the costs related to fuel and CO_2 emission rights, which will be considered later. The values have been obtained from the estimates of Electricity Generation Costs calculated regularly by the Department of Business, Energy and Industrial Strategy (BEIS) of the United Kingdom, and an exchange rate of $e = 1.13$ €/£ has been applied, which was the rate in force at the moment of making the calculations.

Likewise, the estimated years for pre-development T_{pd} and construction T_c are included. The data included in the Table 3 is for projects with a start-up planned for 2020, except for nuclear and coal power plants, which are referred to 2025.

	CCGT ¹	Nuclear ²	Coal ³	Wind ⁴	Solar PV ⁵	Hydro ⁶
T_{pd} [year]	2	5	5	4	1	0
T_c [year]	3	8	5	2	0	2
n [year]	25	60	25	24	25	41
C_{pd} [€/kW]	11.3	271.2	79.1	124.3	79.1	67.8
C_c [€/kW]	565	4633	4746	1356	678	3616
$C_{O\&M_f}$ [€/kW/year]	13.786	88.705	88.705	25.990	6.102	29.041
$C_{O\&M_v}$ [€/MWh]	3.39	3.39	3.39	5.65	0	6.78

¹ CCGT H Class, with a reference plant size of 1200 MW

² Nuclear – PWR (Pressurized Water Reactor) FOAK (First of a kind), with a reference plant size of 3300 MW

³ Coal – CCS (Carbon Capture and Storage) ASC FOAK, with a reference plant size of 624 MW

⁴ Onshore UK > 5 MW, with a reference plant size of 20 MW

⁵ PV > 5 MW, with a reference plant size of 16 MW

⁶ Hydro Large Storage, with a reference plant size of 11 MW

Table 3: Capital and operation costs for different technologies [30]

In order to calculate the capital costs C_{cap} the capacity of the plant P_{plant} needs to be considered:

$$C_{cap} = P_{plant} \cdot (C_{pd} + C_c) \text{ [€]} \text{ (Eq. 40)}$$

Where,

- P_{plant} [kW]: capacity of the electricity generation plant.
- C_{pd} [€/kW]: pre-development costs.
- C_c [€/kW]: construction costs.

Likewise, both the capacity of the plant P_{plant} and the electricity generated each year G_{eli} need to be considered in order to determine the operation costs in each year C_{opi} :

$$C_{opi} = P_{plant} \cdot C_{O\&M_f} + G_{eli} \cdot (C_{O\&M_v} + C_{fuel} + C_{CO_2}) \text{ [€/year]} \text{ (Eq. 41)}$$

Where,

- P_{plant} [kW]: capacity of the electricity generation plant.
- $C_{O\&M_f}$ [€/kW/year]: fixed O&M costs.
- $C_{O\&M_v}$ [€/MWh]: variable O&M costs.
- C_{fuel} [€/MWh]: fuel costs.
- C_{CO_2} [€/MWh]: CO_2 emission rights costs.
- G_{eli} [MWh/year]: electricity generated by the plant in the year i .

Taking into account that the installed capacity of the PV plant would be $P_{PV} = 50 \text{ MW}$, the initial investment costs would amount to $I_{PV} = 37,855,000 \text{ €}$, calculated by the Equation 40. In the case of CCGT power generation plant, on the contrary, a capacity of $P_{CCGT} = 50 \text{ MW}$ is also considered. For this plant, the investment costs would amount to $I_{CCGT} = 28,815,000 \text{ €}$.

3.2.2.- Analysis of the price in the daily market

3.2.2.1.- Electricity sale offers

As explained in in the Section 2.1, the Market Operator establishes an order of the sale offers made by the electricity generators, from the cheapest to the most expensive one, forming the aggregated curve of the sale offers ordered by ascendant price. The order of economic precedence of the purchase offers is, conversely, from the most expensive to the cheapest one, so that the aggregated curve of the purchase offer will has a descending order. The result of the matching process, that is, the cut between both curves, determines the marginal price for each programming period, the same for all the offers matched in the process [4].

Electricity generators present their offers based on the opportunity cost of generating electricity for a certain period, which consists of the costs that would be avoided in the case of not generating and the income given up due to generating. The firsts consist, basically, of the variable O&M costs related to the production of a power generation plant [9] (this is explained more thoroughly in the Appendix 8.2).

It is important to note, however, that opportunity costs differ, in general, from variable costs. Indeed, the income renounced by a thermal power generation plant, for example, does not reflect the price of acquisition of the fuel and CO_2 emission rights, but the price at which they could be resold to a third party, if such possibility exists [9]. Having said that, in order to simplify the present work, it will be assumed that the opportunity cost of the different generation technologies is equal to their variable production costs.

3.2.2.2.- Marginal technology

Based on these costs, as well as on their capacity for regulation, generation technologies play different roles within the power generation park. Non-manageable sources, such as wind or solar PV energy, for instance, are characterized by low variable costs, and take precedence over the rest of technologies in the matching process.

Technologies with a limited regulatory capacity and relatively low variable costs, on the other hand, work as base power generation plants, that is, at a programmed power and without meeting the specific demands of energy during the day. This group would include nuclear power plants, as well as conventional coal-fired power plants. Finally, technologies with a high degree of flexibility, such as CCGTs or pumping turbine, work as peak technologies, meeting the peak demand of electricity during the day.

Depending on the amount of electricity generated by each technology, as well as the demand existing in each programming period, the cut between purchase and sale curves determines a different marginal technology in each case. The influence of renewable energies on this point is crucial, given that, depending on weather conditions, they displace the supply curve, causing the market price to be fixed by more expensive or cheaper technologies [9]. The availability of renewable sources, for their part, responds to a seasonality throughout the year, which is different for each type of resource.

Figure 55 shows, for example, the correlation between hydraulic generation over the months (average data recorder in the period 2010-2017) and the rainfall recorded in each month (historical average). It can be seen that in the summer hydraulic generation decreases considerably, due to the scarcity of water resources, whereas from January to May the highest generation rates are recorded. In the months between September and December, electricity generation increases less than rainfall, which is due to the fact that, in this period, reservoirs are being filled rather than generating electricity, after the usual shortage of summer [20] [34].

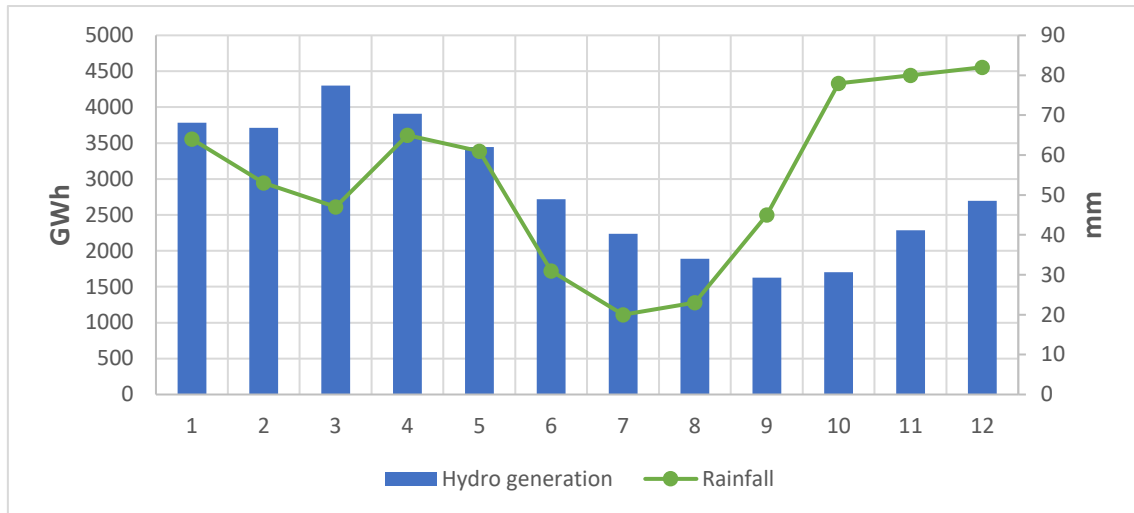


Figure 55: Average hydro electricity generation per month (left) and average rainfall per month (right) (Co-adapted from [20] [34])

Likewise, the electricity generation by solar PV power plants is directly correlated with the levels of radiation recorded throughout the year. Figure 56 shows the relation between solar PV generation (average data recorded in the period 2010-2017) and the average monthly horizontal radiation recorded in southern Spain [35].

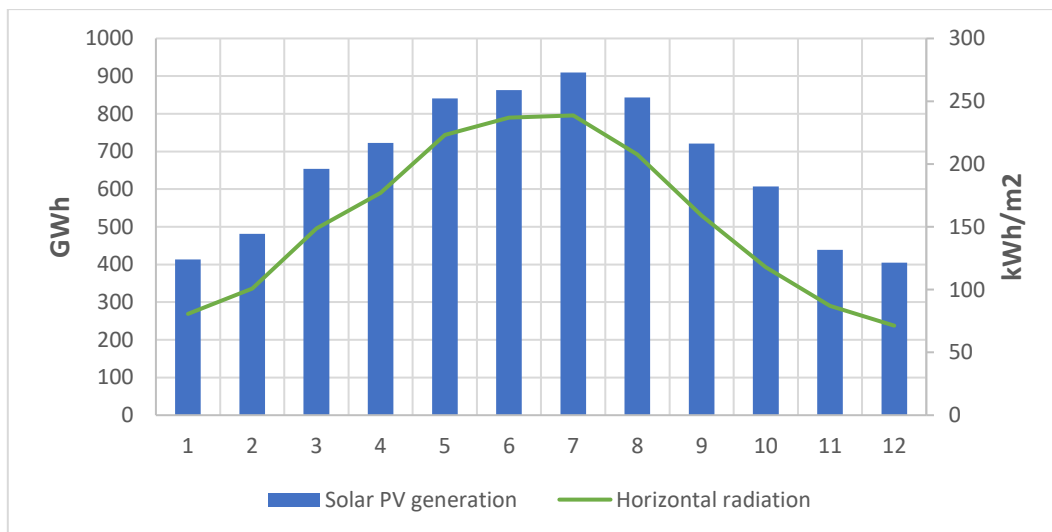


Figure 56: Average solar PV electricity generation (left) and average global horizontal radiation (right) (Co-adapted from [20] [35])

Although data of the distribution of wind availability throughout the year has not been obtained, the average electricity generation by wind power plants obtained from the data of the last 8 years clearly indicates that during winter months the availability of wind is greater, whereas in summer decreases considerably [20].

Given the seasonality of these resources, thus, renewable generation follows a clear profile throughout the year that is transferred, for the reasons mentioned above, to the average marginal price set in the daily market in different months of the year. Figure 57 shows this relationship, which includes the average monthly price registered in the daily market (average

of the data recorder in the period 2010-2017) and the renewable generation (average of the data recorded in the period 2010-2017) [20].

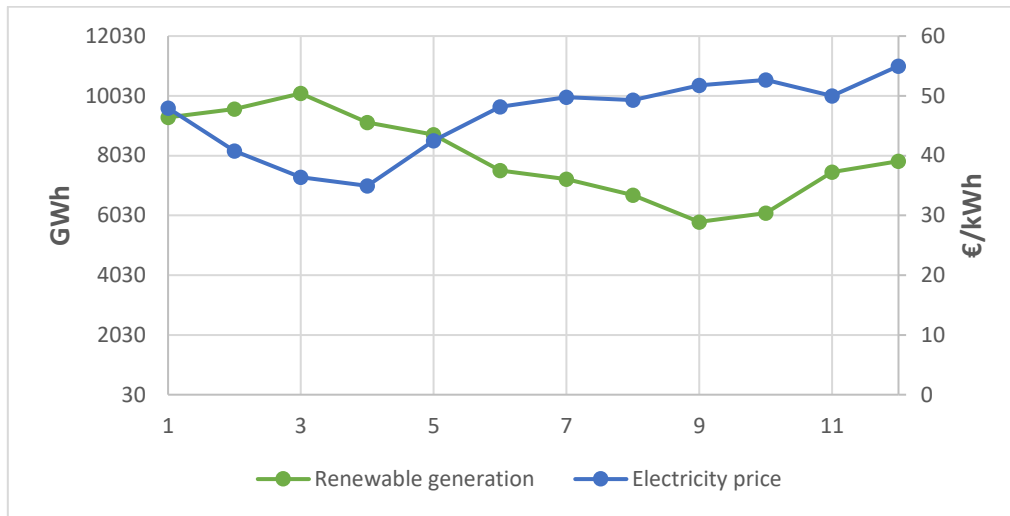


Figure 57: Average renewable electricity generation (left) and average marginal price in the daily market (right) (Co-adapted from [20])

The low participation of renewables during certain periods of the year is compensated by increasing the share of the thermal park in the electricity generation structure. Variable costs of these technologies are higher, owing to the cost of fuel and CO_2 emission rights, inducing a rise in the marginal price received in the market. This correlation is shown in Figure 58, which includes the average marginal price registered monthly in the last 8 years, as well as the contribution of coal and CCGT power plants during that period [20].

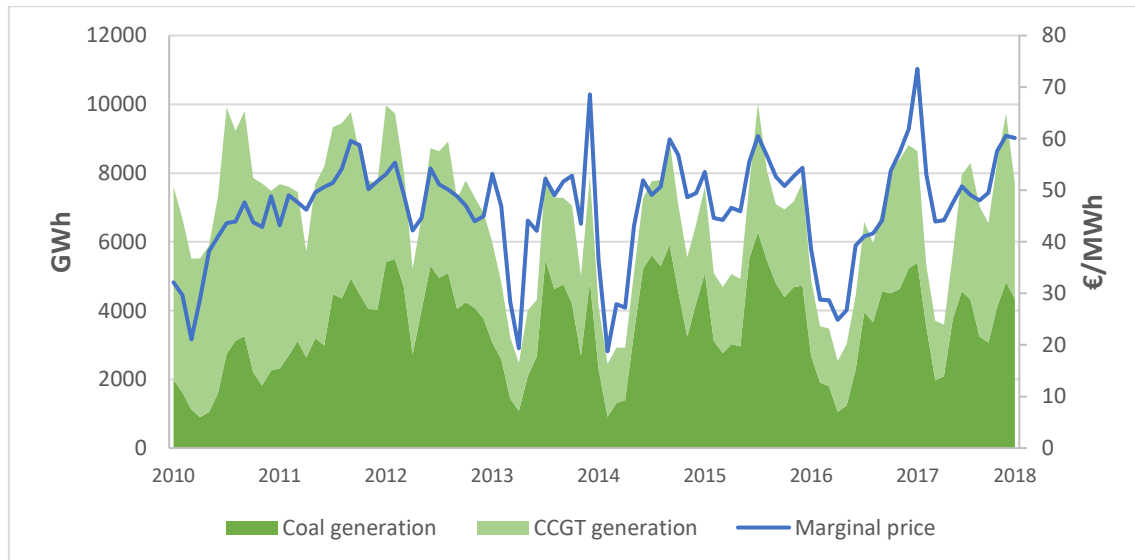


Figure 58: Electricity generation by coal and CCGT (left) and monthly average marginal price in the daily market (right) (Co-adapted from [20])

In order to ensure that this relationship exists, the Pearson correlation coefficient ρ has been calculated by the Equation 42:

$$\rho = \frac{1}{n-1} \cdot \sum_{i=1}^n \left(\frac{x - \mu_x}{\sigma_x} \cdot \frac{y - \mu_y}{\sigma_y} \right) \quad (Eq. 42)$$

Where,

- $\sigma_x = \sqrt{\frac{1}{n-1} \cdot \sum_{i=1}^n (x - \mu_x)^2}$: standard deviation of the variable x .
- $\sigma_y = \sqrt{\frac{1}{n-1} \cdot \sum_{i=1}^n (y - \mu_y)^2}$: standard deviation of the variable y .
- $\mu_x = \frac{1}{n} \cdot \sum_{i=1}^n x$: arithmetic average of variable x .
- $\mu_y = \frac{1}{n} \cdot \sum_{i=1}^n y$: arithmetic average of variable y .
- n : number of data.

According to this, the correlation between the electricity price in the daily market and the electricity generation by CCGT and coal would amount to $r = 0.73$, which is a high positive correlation (see Figure 59).

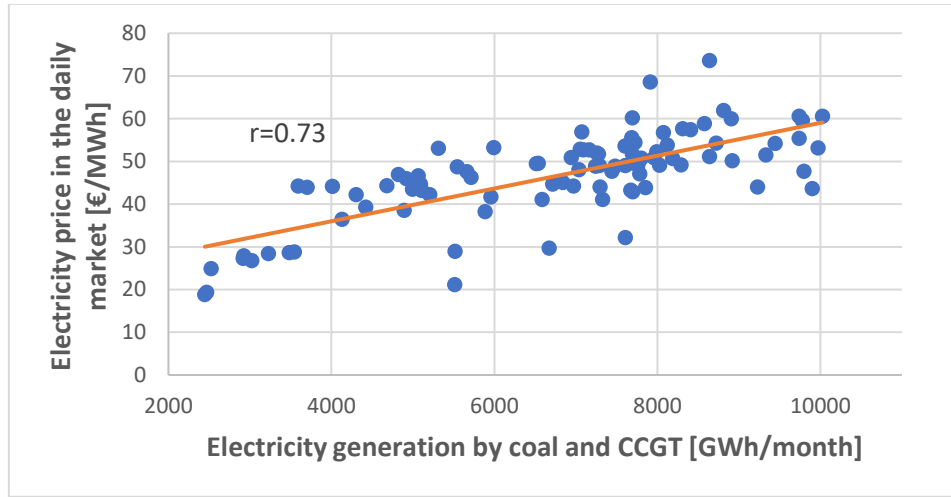


Figure 99: Correlation between electricity Price in the daily market and the electricity generated by CCGT and coal during 2010 and 2017

The percentage of participation of each thermal technology when covering the gap left by renewables will depend, ultimately, on the prices of their respective fuels, that is, coal and natural gas. The price of CO_2 emission rights will also have an unequal influence on both technologies, due to the higher specific emissions generated by coal-fired power plants compared to CCGTs.

Figure 60 shows the electricity generated by coal-fired and CCGT power plants in the last 8 years in Spain, as well as the prices of natural gas (supply cost registered in the Spanish customs) and coal (arithmetic average of South African and Colombian coal price) for that particular period [20] [36] [37]. Here can be seen that in between 2010 and 2012 electricity generation by CCGT was higher, due to low prices of natural gas, whereas during the period 2012-2017 coal-fired power plants have been the protagonists, supported by low prices of coal compared to natural gas, as well as low prices of CO_2 emission rights that have not exceeded, in this period, a maximum of 10 €/ton CO_2 [38].

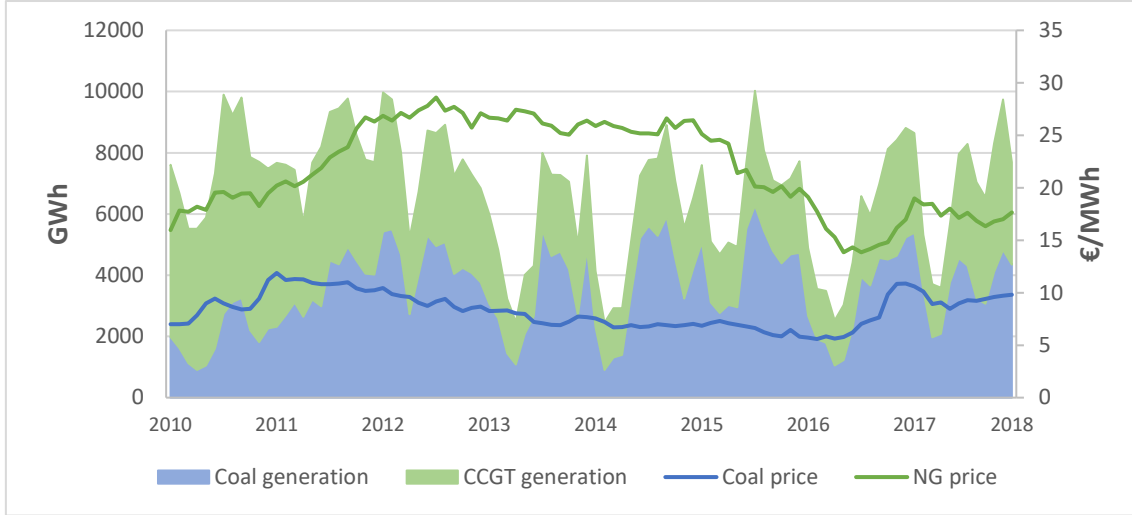


Figure 100: Electricity generation by coal and CCGT (left) and prices of coal and NG in Spain (right) (Co-adapted from [20] [36] [37])

3.2.2.3.- Development of a model to estimate the price in the daily market

From the preceding analysis it can be deduced that the main determining variables of the electricity price are:

1. The generation structure, which affects the technology that is marginal in the matching process and, therefore, in the variable costs considered in the formation of the electricity price.
2. The prices of energy products, which influence the variable costs of certain technologies, inducing a greater or lesser participation in the generator park.

With the aim of being able to estimate the electricity price in the operating period of the solar PV plant, that is, 2020-2045, the forward curve of the marginal price in the daily market will be constructed for this period. For a first approximation and taking into account the results of the previous analysis, it has been considered that the price is proportional to the sum of the products between the generation of each technology and its variable costs. Thus, the marginal price P_{el} for each month would be as follows:

$$P_{el} = \frac{1}{G_{total}} \sum_{i=1}^n G_i \cdot C_{v_i} \text{ [€/MWh]} \text{ (Eq. 43)}$$

Where,

- G_i [GWh/month]: electricity generation per month by technology i .
- G_{total} [GWh/month]: total electricity generation per month.
- C_{v_i} [€/MWh]: variable costs of technology i .
- n : number of electricity generation technologies.

Calculation of variable costs

With the aim of simplifying the analysis, and given the assumptions made in the Section 3.1, according to which wind and solar PV will be the predominant technologies in the Spanish future

generator park, the technologies considered for calculating the price of electricity are the followings:

- Hydraulic generation.
- Nuclear generation.
- Coal generation.
- CCGT generation.
- Wind generation.
- Solar PV generation.
- Pumping turbine generation.

Hydraulic, wind and solar PV generation

In the case of technologies that do not consume any type of fuel, such as hydraulic, wind and solar PV, their variable costs C_v will be only determined by the variable O&M costs:

$$C_v = C_{O\&M_v} [\text{€/MWh}] \text{ (Eq. 44)}$$

Where,

- $C_{O\&M_v} [\text{€/MWh}]$: variable O&M costs included in Table 1.

Nuclear generation

In the case of nuclear power plants, on the other hand, the variable cost C_v will depend on both the variable O&M costs and the cost of uranium used for power generation:

$$C_v = C_{O\&M_v} + \frac{1}{10^3 \cdot E_{U_3O_8}} \cdot P_{fc} [\text{€/MWh}] \text{ (Eq. 45)}$$

Where,

- $C_{O\&M_v} [\text{€/MWh}]$: variable O&M cost included in Table 3.
- $E_{U_3O_8} [GWh/ton U_3O_8]$: the amount of specific energy obtained from U_3O_8 .
- $P_{fc} [\text{€/ton } U_3O_8]$: equivalent price of the complete fuel cycle, referenced to U_3O_8 .

For the calculation of $E_{U_3O_8}$ and P_{fc} , and in order to simplify the calculations, it is considered that, initially, there is only one type of particle in the reactor, U_{235} , that by means of a fission process (neutrons will be neglected) results in the products Rb_{94} and Cs_{141} :

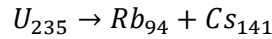


Table 4 includes the binding energies of each element considered in the previous reaction, as well as the corresponding number of nucleons:

	$E_B [\text{MeV/nucleon}]$	$n [\text{nucleons}]$
U_{235}	7.6	235
Rb_{94}	8.5	94
Cs_{141}	8.3	141

Table 4: Binding energy and number of nucleons for each element

Based on the nuclear reaction considered above, the energy released $E_{released}$ by each gram of U_{235} is determined by the Equation 48, where the binding energies E_B and number of nucleons n have been used, as well as Avogadro number N_A and the atomic mass of U_{235} , $M_{U_{235}}$. For a greater clarity in the expression, a multiplicative factor f has been used for the relation among the different units.

$$E_{released} = [(E_B \cdot n)_{Rb_{94}} + (E_B \cdot n)_{Cs_{141}} - (E_B \cdot n)_{U_{235}}] \cdot \frac{N_A}{M_{U_{235}}} \cdot f$$

$$= 7.42 \cdot 10^{10} [J/g U_{235}] \text{ (Eq. 46)}$$

Where,

- $(E_B \cdot n)_{Rb_{94}} = 8.5 [MeV/nucleon] \cdot 94 [nucleons/fission]$.
- $(E_B \cdot n)_{Cs_{141}} = 8.3 [MeV/nucleon] \cdot 141 [nucleons/fission]$.
- $(E_B \cdot n)_{U_{235}} = 7.6 [MeV/nucleon] \cdot 235 [nucleons/fission]$.
- $N_A = 6.022 \cdot 10^{23} [atoms U_{235}/mol U_{235}]$.
- $M_{U_{235}} = 238.03 [g U_{235}/mol U_{235}]$.
- $f = \frac{10^6 [eV]}{1 [MeV]} \cdot \frac{1.6 \cdot 10^{-19} [J]}{1 [eV]} \cdot \frac{1 [fission]}{1 [atom U_{235}]}$.

Given that the price of the uranium in the present work is referred to uranium oxide U_3O_8 , it is necessary to determine the specific energy $E_{U_3O_8}$ obtained by this element. For this purpose, the mass percentage of the different isotopes present in natural uranium U have been considered (see Table 5):

	Composition of U
U_{238}	99.275 %
U_{235}	0.72 %
U_{234}	0.005 %

Table 5: composition of natural uranium by means of mass percentage of each isotope

Once the percentage of U_{235} contained in U is known, the relation between the energy released per gram of U_{235} and the amount electricity achieved per unit of mass of U_3O_8 , $E_{U_3O_8}$, can be established. For that, the atomic masses of uranium M_U and uranium dioxide $M_{U_3O_8}$ have been used, as well as the content of 0.72% of U_{235} , included in the factor f . The relation between the thermal energy released by the fuel and the electric power generated, finally, is given by the performance of the nuclear reactor $\eta_{nuclear}$, for which a value of 36% will be considered [39]:

$$E_{U_3O_8} = \frac{\eta_{nuclear} \cdot E_{released} \cdot M_U}{M_{U_3O_8}} \cdot f = 45.3 [GWh/ton U_3O_8] \text{ (Eq. 47)}$$

Where,

- $M_U = 238.03 [g U/mol U]$.
- $M_{U_3O_8} = 842.09 [g U_3O_8/mol U_3O_8]$.
- $\eta_{nuclear} = 36[\%]$.
- $f = \frac{1 [Wh]}{3600 [J]} \cdot \frac{1 [GWh]}{10^9 [Wh]} \cdot \frac{0.72 [g U_{235}]}{100 [g U]} \cdot \frac{3 [mol U]}{1 [mol U_3O_8]} \cdot \frac{10^6 [g U_3O_8]}{1 [ton U_{235}]}$.

Lastly, in the case of nuclear power plants, the cost of fuel does not only refer to the supply of U_3O_8 , but also to the cost of all the stages included in the nuclear fuel cycle. Table 6 shows the different stages, as well as their weight in the cost resulting from the complete cycle:

Stage	Cost structure [%]
1.- Exploration, mining and milling uranium concentrates U_3O_8	25
2.- Conversion to UF_6	5
3.- Enrichment	30
4.- Conversion to UO_2 and fuel fabrication	15
5.- Back-end costs	25

Table 6: Weight of each stage in the cost of the total fuel cycle

Since the price which is known is that of U_3O_8 , the equivalent cost of nuclear fuel cycle P_{fc} is calculated by Equation 48. This is the approximate price that will be used to calculate the variable cost of nuclear generation expressed in Equation 45.

$$P_{fc} = \frac{P_{U_3O_8}}{0.25} [\text{€/ton } U_3O_8] \text{ (Eq. 48)}$$

Where,

- $P_{U_3O_8}$ [€/ton U_3O_8]: price of U_3O_8 .

Coal and CCGT generation

As far as thermal technologies are concerned, their variable costs will include variable O&M costs, fuel costs (coal or natural gas) and the price of CO_2 emission rights:

$$C_v = C_{O\&M_v} + \frac{1}{\eta_{fuel}} \cdot P_{fuel} + \frac{E_{CO_2}(fuel)}{10^3 \cdot G} \cdot P_{CO_2} [\text{€/MWh}] \text{ (Eq. 49)}$$

Where,

- $C_{O\&M_v}$ [€/MWh]: variable O&M costs.
- η_{fuel} [%]: efficiency of the generation technology.
- P_{fuel} [€/MWh]: fuel price.
- $E_{CO_2}(fuel)$ [ton CO_2 /month]: CO_2 emissions.
- G [GWh/month]: electricity generation by month.
- P_{CO_2} [€/ton CO_2]: CO_2 emission prices.

In order to estimate the amount of fuel consumed by each technology, the electricity generated by each fuel G_{fuel} has been compared to the amount of fuel consumed to generate the said electricity:

$$\eta_{fuel} = \frac{G_{fuel}}{C_{fuel}} \cdot 100 [\%] \text{ (Eq. 50)}$$

In the case of coal, data from the period 2011-2016 has been analysed, and an average efficiency of $\eta_{coal} = 36\%$ has been calculated (see Figure 61) [20] [40]. For CCGTs, on the contrary, data referring to the period 2010-2017 has been considered, and despite some fluctuations, the

efficiency of this technology is around an average value of $\eta_{CCGT} = 49\%$ (see Figure 62) [20] [37].

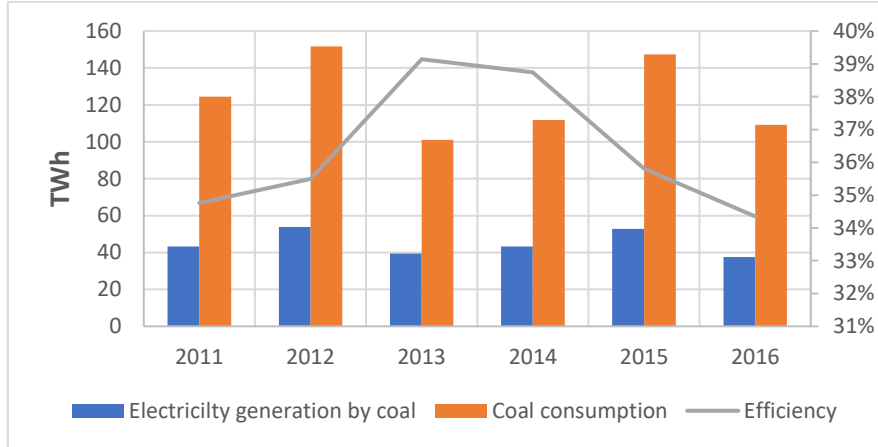


Figure 61: Electricity generation by coal and coal consumption (left) and calculated efficiency (right) (Co-adapted from [20] [40])

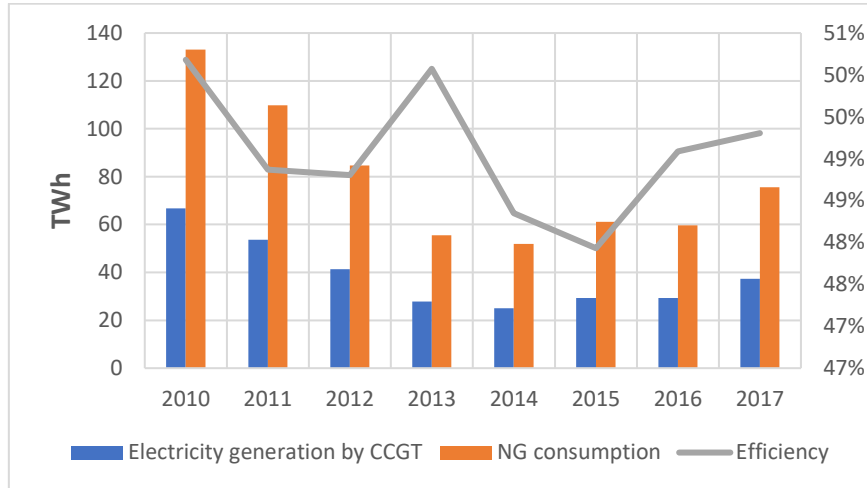


Figure 62: Electricity generation by CCGT and natural gas consumption (left) and calculated efficiency (right) (Co-adapted from [20] [37])

Once efficiencies have been obtained, the monthly fuel consumption has been calculated for each technology, based on the amount of electricity generated. In the case of coal, a Lower Heating Value (LHV) of $LHV_{coal} = 6450 \text{ kcal/kg}$ has been considered, resulting in the following coal consumption C_{coal} :

$$C_{coal} = \frac{G_{coal}}{\eta_{coal} \cdot LHV_{coal}} \cdot f \text{ [ton/month]} \text{ (Eq. 51)}$$

Where,

- G_{coal} [GWh/month]: electricity generation per month by coal-fired power plants.
- $LHV_{coal} = 6450$ [kcal/kg]: LHV of coal.
- $\eta_{coal} = 36$ [%]: approximate efficiency of coal-fired power plant in Spain.
- $f = \frac{10^6 \text{ [kWh]}}{1 \text{ [GWh]}} \cdot \frac{860 \text{ [kcal]}}{1 \text{ [kWh]}} \cdot \frac{1 \text{ [ton]}}{10^3 \text{ [kg]}}$.

In the case of natural gas, on the other hand, it has been necessary to determine its composition to calculate its LHV. Table 7 shows the different components of the gas, their percentages in volume and the LHV related to them, as well as the final LHV of natural gas $LHV_{NG} = 36,907 \text{ kJ/m}^3$ (Algerian natural gas data, which is the predominant supplier in the Spanish gas system) [41].

Component	%Vol	LHV [kJ/m ³]
CH_4	91.2	35,883
C_2H_6	6.5	64,345
C_3H_8	1.1	-
C_4H_{10}	0.2	-
N_2	1	-
Total		36,907

Table 7: Components of natural gas, their percentage in volume and LHV [41]

Once LHV_{NG} is calculated, and knowing also the efficiency η_{CCGT} of CCGT power plants, the monthly consumption of natural gas C_{NG} can be determined:

$$C_{NG} = \frac{G_{CCGT}}{\eta_{CCGT} \cdot LHV_{NG}} \cdot f \text{ [m}^3/\text{month]} \text{ (Eq. 52)}$$

Where,

- G_{CCGT} [GWh/month]: electricity generated per month by CCGT power plants.
- $LHV_{NG} = 36,907 \text{ [kJ/m}^3]$: LHV of Algerian natural gas.
- $\eta_{CCGT} = 49 \text{ [%]}$: approximate efficiency of CCGT power plants in Spain.
- $f = \frac{10^6 \text{ [kWh]}}{1 \text{ [GWh]}} \cdot \frac{3600 \text{ [kJ]}}{1 \text{ [kWh]}}$.

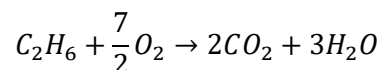
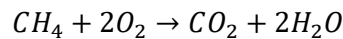
Finally, emissions produced per month by coal-fired power plants $E_{CO_2}(\text{coal})$ can be calculated based on the monthly coal consumption C_{coal} and the molar masses of carbon and carbon dioxide, M_C and M_{CO_2} , respectively:

$$E_{CO_2}(\text{coal}) = C_{coal} \cdot \frac{M_{CO_2}}{M_C} \cdot f \text{ [ton CO}_2/\text{month]} \text{ (Eq. 53)}$$

Where,

- $M_{CO_2} = 44 \text{ [kg CO}_2/\text{kmol CO}_2]$.
- $M_C = 12 \text{ [kg/kmol]}$.
- $f = \frac{10^3 \text{ [kg C]}}{1 \text{ [ton C]}} \cdot \frac{1 \text{ [kmol CO}_2]}{1 \text{ [kmol C]}} \cdot \frac{1 \text{ [ton CO}_2]}{10^3 \text{ [kg CO}_2]}$.

For the calculation of the emissions generated by CCGT power plants, on the other hand, the different chemical reactions that occur in the combustion of natural gas must be considered, so that a molar relation between the burnt natural gas and CO_2 emitted can be established:



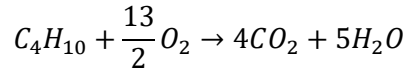
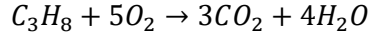


Table 8 shows the molar ratio of each component with CO_2 , calculated from the molar ratios in the chemical reactions and their percentage in volume included in Table 7. The global molar ratio between natural gas and carbon dioxide takes a value of $f_{mol} = 1.083 \text{ mol } CO_2/\text{mol NG}$.

Component	$f_{mol}[\text{mol } CO_2/\text{mol NG}]$
CH_4	0.912
C_2H_6	0.13
C_3H_8	0.033
C_4H_{10}	0.008
Total	1.083

Table 8: molar relation between each component of natural gas and CO_2

Finally, assuming that natural gas responds to the model of natural gas, according to which the molar volume takes a value of $V_{mol} = 22.4 \text{ l NG/mol NG}$, as well as considering the molar mass M_{CO_2} , the monthly emissions generated by CCGT power plants can be calculated based on their consumption of natural gas C_{NG} :

$$E_{CO_2}(CCGT) = \frac{C_{NG} \cdot f_{mol} \cdot M_{CO_2}}{V_{mol}} \cdot f [\text{ton } CO_2/\text{month}] \text{ (Eq. 54)}$$

Where,

- $f_{mol} = 1.083 [\text{mol } CO_2/\text{mol NG}]$.
- $M_{CO_2} = 44 [\text{g } CO_2/\text{mol } CO_2]$.
- $V_{mol} = 22.4 [\text{l NG/mol NG}]$.
- $f = \frac{10^3 [\text{dm}^3]}{1 [\text{m}^3]} \cdot \frac{1 [\text{ton } CO_2]}{10^6 [\text{g } CO_2]}$.

Pumping turbine generation

As mentioned above, the pumping turbine power plants work as peak technologies, meeting the energy demand during peak hours and storing the energy (pumping) in off-peak hours (low demand). In the pumping process, therefore, these plants buy the electricity necessary to store the water in the wholesale electricity market, so their variable costs are proportional to the marginal price in the market.

Since the pumping takes place in hours of low demand, the purchase price received by these plants is lower than the price at which they sale their electricity in peak hours. In order to simplify the work, nevertheless, it will be considered that the variable cost C_v of these power plants is equal to the average monthly price they have received in the last 8 years (see Figure 63) [20]:

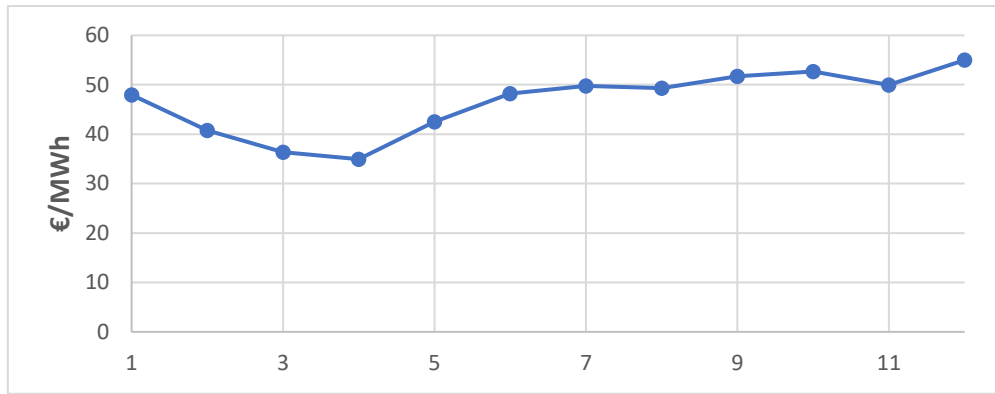


Figure 63: Average monthly marginal price in the daily market (Co-adapted from [20])

Results of the model

Once the variable costs for each generation technology have been obtained, by means of Equation 43, the global cost of electricity offered in the daily market has been calculated for the period 2010-2017. These costs represent an approximation of the costs on which the electricity sales offers are based when formulating their prices. Figure 64 shows the results obtained by the model, as well as the real average marginal price perceived in the daily market in the last 8 years [20]:

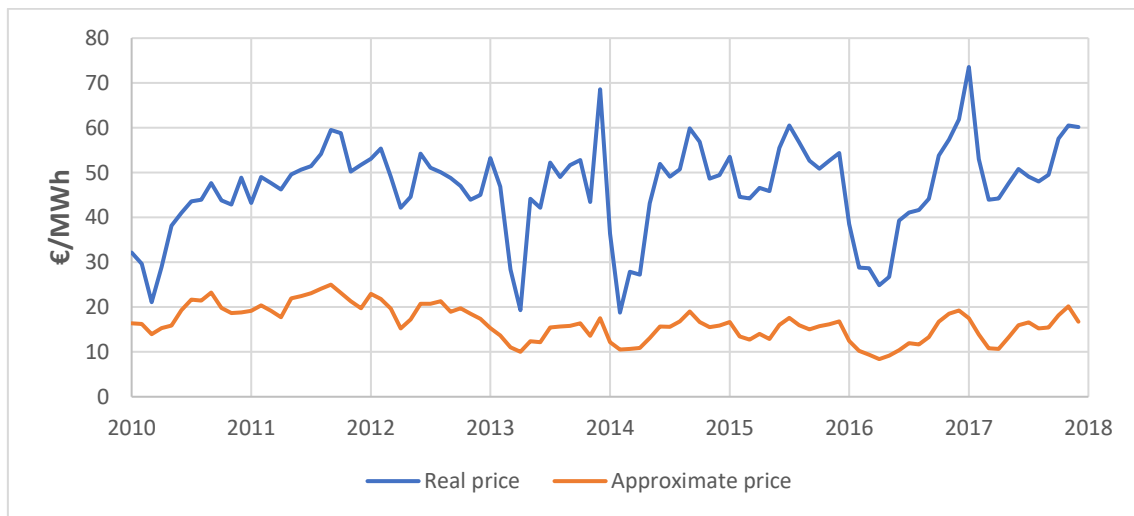


Figure 64: Average monthly marginal price in the daily market (blue) and the approximate price calculated with the model (orange)

As it can be seen, the results obtained follow, in some way, to the fluctuations of the price in the daily market, which confirms the dependence between the marginal price, on the one hand, and the generation structure and the prices of energy products, on the other hand. Despite the correlation between their profiles, however, the values obtained in the model are far from the real price perceived in the market. This fact could be a result of some of the following factors:

- It has been assumed that electricity sales offers are based on their variable costs, and not on their opportunity cost, which are actually the ones that determine the price.
- With the aim of simplifying the analysis, some technologies have been ignored, which can turn out to be marginal technologies and, thus, determine the price.

- No profit margin has been considered, so that the variable cost of electricity generation is equal to the price offered in the market.

Nevertheless, the main reason for the divergence between both prices is that, despite the clear dependence of the generation structure, not all technologies have the same influence over the price of electricity. Indeed, due to the ascending order of the sales offers curve in the matching process, certain technologies result marginal more frequently, whereas others do not influence the price at all, despite being an important part of the generation structure. This fact can be seen in Figure 64, where, despite a similarity in the profile of both prices, the fluctuations of the real price have a greater amplitude than those obtained by the model.

In order to determine the importance of each technology in the process of forming the marginal price in the market, the initial model has been modified with the insertion of weight w_i for each technology i . These weights represent, approximately, the degree of influence that each technology has over the price, beyond the share of each one in the electricity generation mix. The marginal price calculated by the new model, therefore, is as follows:

$$P_{el} = \frac{1}{G_{total}} \sum_{i=1}^n w_i \cdot G_i \cdot C_{vi} \text{ [€/MWh]} \text{ (Eq. 55)}$$

Where,

- G_i [GWh/month]: electricity generation per month by technology i .
- G_{total} [GWh/month]: total electricity generation per month.
- C_{vi} [€/MWh]: variable costs of technology i .
- n : number of electricity generation technologies.
- w_i : weight of technology i .

For the calculations of these weights, the optimization tool SOLVER available in Excel has been used, by which the values that minimize the sum of the deviations between the real and approximate prices have been determined, for the period 2010-2017:

$$\min \sum_i |P_{real} - P_{model}| \text{ (Eq. 56)}$$

Table 9 includes the values for the weight of each technology, by which an average error of less than 4.3 €/MWh is achieved.

	Hydro	Nuclear	Coal	CCGT	Wind	Solar PV	Pumping
w_i	4.13	7.03	4.97	0	5.93	0	0.89

Table 9: Weights for the different electricity generation technologies

The results obtained base on the modifications made to the initial model are included in Figure 65. It shows the relative convergence between the real price and the price estimated by the model for the period 2010-2017.

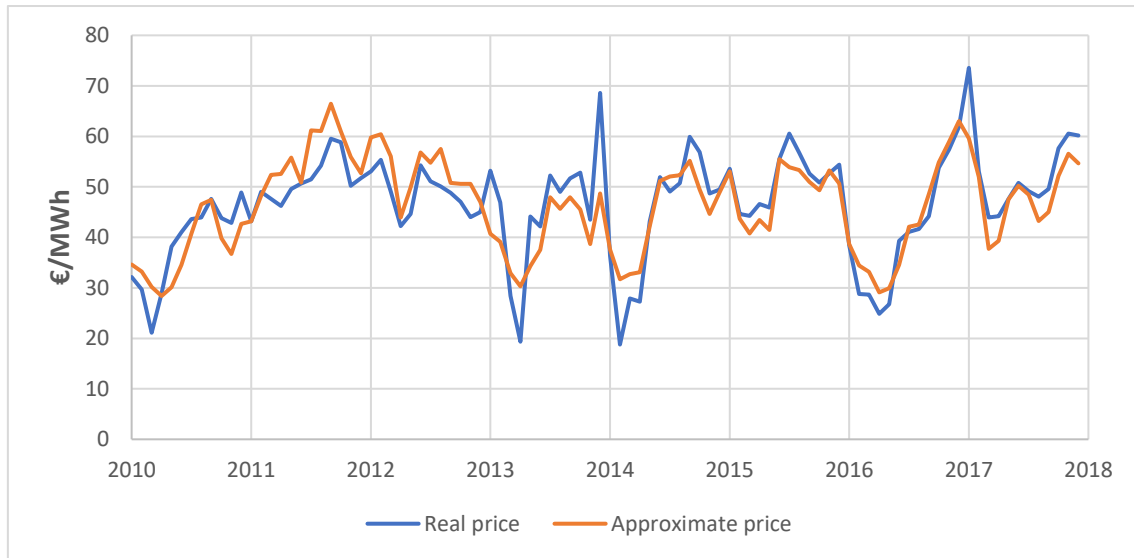


Figure 65: Average monthly marginal price in the daily market (blue) and the approximate price calculated with the final model (orange)

The Pearson correlation coefficient between the real price and the one calculated by the model amounts to $r = 0.86$, which means that the relation between them is high and, therefore, the price foreseen by the model is reliable (see Figure 66).

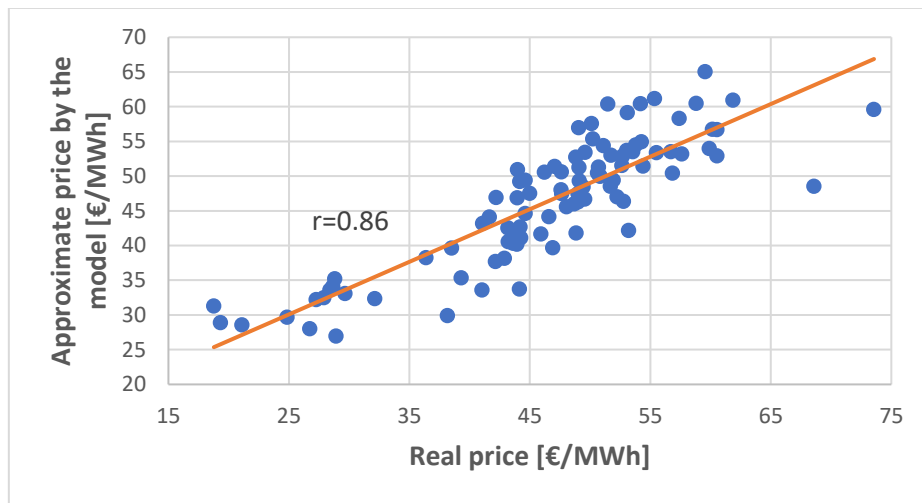


Figure 66: Correlation between the real price and the approximate price of the model during the period 2010-2017

Given the similarity between both prices, the forecasts for the price of electricity for the period 2020-2050 made in the following section will be based on this model. However, due to the expected energy transition for the coming years, according to which coal will have disappeared from the generator mix by 2030, the influence of CCGT on the price of electricity is expected to increase in the future. To take into account these changes, then, a progressive change between the weights of both technologies will be considered, so that in 2030 their respective values are $w_{coal} = 0$ and $w_{CCGT} = 4.97$.

3.2.3.- Forecasts of the price of the electricity in the daily market

Given that the variable costs of certain technologies are influenced by the price of fuels or CO_2 emission rights, the evolution of these ones during the period 2020-2050 will have an impact on the evolution of the price of electricity. Therefore, in order to make the forward curve of the price of electricity in the daily market, it will also be necessary to make the forward curve of the prices of the different fuels and CO_2 emission rights. With this objective, a brief analysis of their respective markets has been carried out, explaining the principal factors that have historically influenced their evolution and the forecasts for the period 2020-2050.

3.2.3.1.- CO_2 emission rights

Introduction

The Kyoto Protocol of 1997 established legally binding commitments to reduce or limit GHG emissions, which promoted the creation of political instruments to meet those objectives (see more information about the Kyoto Protocol in the Appendix 8.1). With Directive 2003/87/EC, the European Union established an EU Emissions Trading Scheme (EU ETS) that became operational in 2005, and whose objective was to promote the reduction of GHG emissions in an economically efficient and cost-effectively way [42].

On the one hand, this regime limits the global volume of GHG emitted by energy-intensive industries, electricity producers and, currently, airline companies as well. The value for this limit is determined by the emission reduction objectives established by the EU [42]. On the other, it obliges these companies to acquire emission rights by means of which they can carry out their activities. Each right allows to emit a ton of CO_2 or the equivalent amount of NO_2 (nitrous oxide) or PFC (perfluorocarbons) and can be traded freely through the EU [42].

Initial phase

The period between 2005 and 2007 (Phase 1) worked as a pilot phase where the free trade of rights was established, as well as the necessary infrastructure for monitoring the emissions generated by the parties. Its application was exclusively limited to emissions generated by electricity producers and energy-intensive industries, and virtually all the emission rights were assigned free of charge [42].

The second phase (2008-2013), on the other hand, coincided with the first period of the Kyoto Protocol, in which the countries integrated in the EU ETS had to meet specific emission reduction targets. For this, the maximum limit of emission rights was reduced by 6.5% compared to the 2005 figures, and the free concession of emission rights fell slightly, reaching around 90% of the total assigned rights [42].

Throughout these two phases, the emission rights market experienced an intense development. In the first phase, the trading volume grew from 321 *million* assigned rights in 2005 to 2100 *million* in 2007, whereas in 2012 the rights negotiated in the regime reached the figure of 7900 *million* [42]. Due to a surplus of rights in the market, however, prices throughout this period remained well below those necessary to encourage investment in technologies with low level of emissions [42].

In the first phase, the surplus of duties was owing to the absence of reliable data on emissions, which led to establishing the maximum limits based on estimates that exceeded the real emissions. As a result, the offer of rights in the market was much higher than the demand, causing a price drop from a maximum of 30 €/ton CO_2 to 1 €/ton CO_2 [42] [43].

In the second phase, the maximum limits of emission rights were reduced according to the emissions recorder in the initial phase. However, due to the economic crisis of 2008, the reduction in industrial activity and, consequently, the demand for emission rights, was greater than expected, causing once again a surplus of rights. This fact, together with the possibility of buying international credits equivalent to the emission rights, had a severe impact on the price of CO_2 , which ended up below 5 €/ton CO_2 at the end of the second phase, as can be seen in the Figure 67 [42] [38].



Figure 67: CO_2 price during the second phase of EU ETS (Co-adapted from [38])

Current phase

During the current marketing period (Phase 3), between 2013 and 2020, 57% of the rights is being auctioned, whereas the rest is being assigned free of charge. Companies of electricity sector are obliged to buy CO_2 emission rights, whereas airline companies will receive most of their rights for free until 2020. The free allocation of rights for the energy-intensive industry, for its part, will decrease over the period, with the aim of mitigating the initial impact on their competitiveness and, thus, reducing the risk of “carbon leakage” [42].

At the beginning of Phase 3, the emission limit was set at 2084 *million* of emission rights, and a linear reduction of 1.74% per year was established. This figure implies a reduction of more than 38 *million* of emission rights per year, which implies that the limit of emission rights in 2020 will be 21% lower than in 2005 [42]. Likewise, with the objective of reducing the surplus of rights in the market, the EU has postponed the auction of 900 *million* rights. In the same sense, a Stability Reserve has been established by which it is expected to improve the resilience of the system in the face of inequalities between supply and demand [42].

As shown in Figure 68, however, the measures taken by the EU have been insufficient to establish the price of the rights at a level that could be useful for the decarbonization process, which is estimated to be above 20 €/ton CO_2 [44].

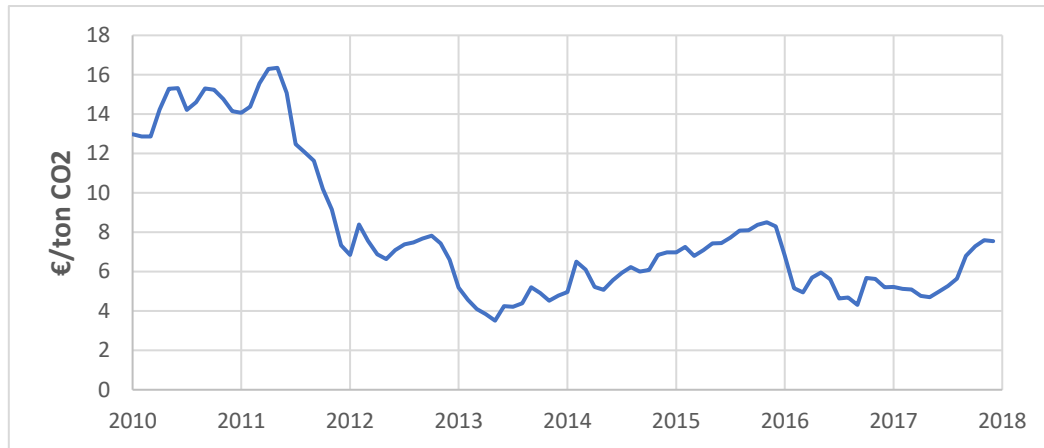


Figure 68: CO2 price in the last decade (Co-adapted from [38])

Forecasts of the price of CO₂ emission rights

In order to achieve the objective set by the EU to reduce emissions by 40% in 2030 compared to 1990, the emission limit should decrease at a linear rate of 2.2% per year during Phase 4, which comprises the period 2021-2030. With this reduction, in 2030 emissions would have reduced by 43% below the levels of 2005, which represents a decrease of 556 million tons [42]. Likewise, according to estimates made by the Stability Reserve, it will be necessary to remove 12% of the rights each year to solve the surplus problem in the current market [44].

However, these decisions have not influenced an increase in the price of CO₂ yet, which calls into question the effectiveness of the current market based on volumes (credit delay and Stability Reserve). Several Member States have already introduced measures at national level, setting a minimum market price by which the necessary incentive for the energy transition is created [43] [44].

Along these lines, the EU is expected to take measures in line with national measures, establishing a floor for the price of CO₂ in the auctions, so that rights are not sold at a price below a minimum. The estimated price to promote the shift from coal to gas is approximately 20 €/ton CO₂ in 2020 and 25 €/ton CO₂ in 2025, so they will be taken as reference values of the price of CO₂ in the medium term [44]. In the long term, values between 20 €/ton CO₂ and 250 €/ton CO₂ are expected, with an average value of 80 €/ton CO₂ [45].

Figure 69 shows the forward curve of the price of CO₂ calculated for the period 2020-2050, for which a linear increase has been assumed between the reference values of 20 €/ton CO₂ in 2020, 25 €/ton CO₂ in 2025 and 80 €/ton CO₂ in 2050.

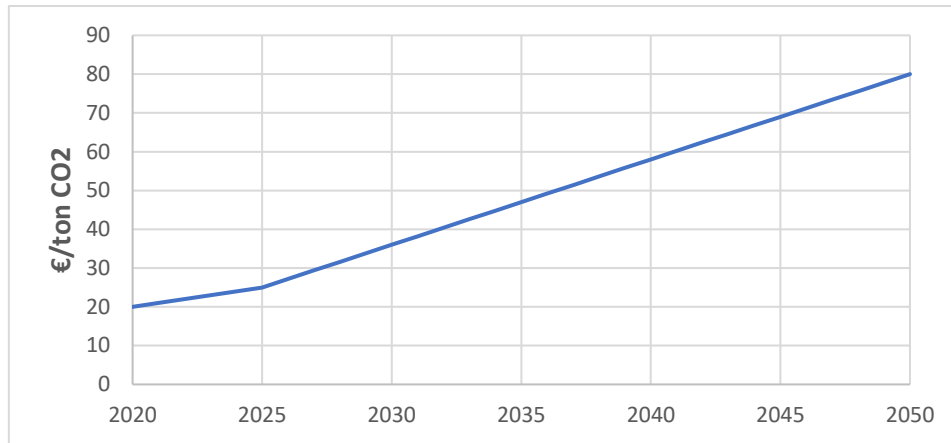


Figure 69: CO₂ price forward curve, 2020-2050

3.2.3.2.- Natural gas

Introduction

As it has been seen in the Section 2.2, natural gas (NG) is called to play a crucial role in the transition to a decarbonized economy, given its low GHG emissions compared to coal and oil. In addition, its importance has been reinforced in the last decade due to the new techniques for extracting natural gas (shale gas), as well as the development of the liquified natural gas (LNG) market [33]. In this context, according to the forecasts of IEA an increase of 1.6% per year is expected for the global consumption of NG until 2022, whereas the expected long-term growth will be around 1.4% per year until 2040 [33].

Unlike the oil market, considered as global and integrated, the global NG market is structured in three regional markets (United States, Europe and Asia), whose prices depend, mainly, on structural (also circumstantial) characteristics of each region. However, historically the price of NG has been closely related to that of oil in all the regions, considered as substitutable by the industries. Thus, the price of NG has been traditionally fixed by indexation formulas to the price of oil, normally with a time lag, so that the price of oil at a given moment determined the price of NG in the next months [33].

For this reason, despite the substantial differences between the prices of NG in the different regions, fluctuations in the price of oil have had an impact, to a greater or lesser extent, on the evolution of the price of NG. Figure 70 shows the evolution of the price of Brent oil (the reference oil in Europe), as well as the reference price of NG for the different regions in the last decade (Henry Hub in USA, NBP in Europe and the price of LNG in Asia):

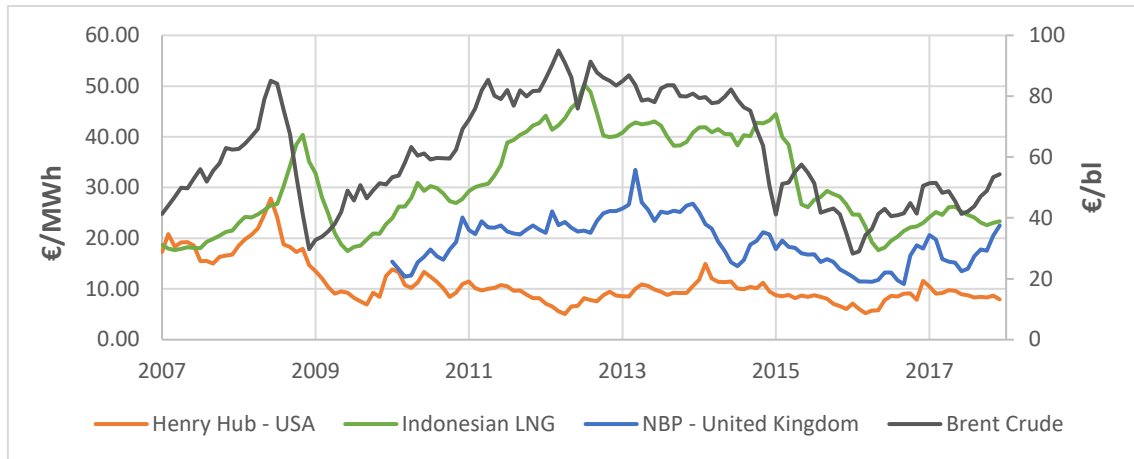


Figure 70: Evolution of Brent crude and natural gas prices for different regions, 2007-2017 (Co-adapted from [46] [36] [47])

Petroleum

Due to speculative movements, the oil market is strongly influenced by expectations, especially those related to economic growth, geopolitical conflicts that may affect the production, as well as to the strategic decisions of OPEC (Organization of the Petroleum Exporting Countries) and, in parallel, of the non-OPEC producer countries [48]. As it can be seen in Figure 70, from the end of 2014 to the beginning of 2016, the price of oil fell precipitously, due to an increase in supply led by the United States and the slowdown in the growth of demand [15]. Despite a gradually recovery since then, the price of the oil barrel amounted, in December 2017, to 50,56 €/bl, far from the 90 €/bl reached in 2012 [46].

In this sense, the long-term outlook depends to a large extent on the position taken regarding the nature of the fall in prices in the recent years. The IEA has developed two alternative scenarios, one in which this decline is considered a mere cyclical event and another in which structural changes in the production and consumption of oil at a global level are adduced. In the first scenario, the price of the oil barrel is expected to reach 80 \$/bl in 2020, returning in the long term to prices equal to those registered in 2014, which would be around 113 \$/bl in 2030 and 128 \$/bl in 2040 [15]. In the second, a price of 50 \$/bl is estimated for 2020, whereas in 2040 the price would not exceed 85 \$/bl [15].

Due to the reduction agreed by the OPEC countries regarding the production of oil, however, in the last year the price of oil has shown a clearly upward trend, standing above the forecasts made in the second scenario. Thus, the price of oil is expected to recover in the coming years. The pace of long-term growth, however, will depend to a large extent on the technological advances that are made in terms of electric batteries for vehicles, as well as the growth rate of the vehicle fleet in emerging countries [15].

Regional natural gas markets

As shown in Figure 70, the influence of the price of oil on the price of NG varies significantly from one region to another. The natural gas market in the United States, for instance, is currently characterized by a balance between local supply and demand. This is due to the increase in domestic production (shale gas) that occurred between 2007 and 2013, based on non-

conventional extraction techniques, which went from 5% of total production in 2000 to 40% in 2013 [51]. As a result, NG prices fell by 45% during this period, reaching levels that have remained relatively constant until today [49]. This evolution contrasts with the fluctuations in the price of oil, evidencing a clear decoupling of both prices in the US natural gas market [33].

In the European market it is also happening a certain decoupling between the prices of both commodities, with important differences, however, between the north and the south of Europe. In general, however, contracts indexed to Brent oil have gone from representing 70% of contracts in 2005 to 30% in 2015 [48]. Conversely, contracts indexed to the prices of NG in the European hubs (virtual natural gas trading points) are increasing, which are called *gas-to-gas* [33].

This change is occurring gradually but steadily worldwide, as shown in Figure 71. Traditional contracts were normally long-term, with relatively little flexibility in volumes and prices indexed to the prices of oil. But in recent years the form of contracting NG has evolved towards a model based on short-term contracts, with greater flexibility in supply and prices determined by *gas-to-gas* mechanisms [33].

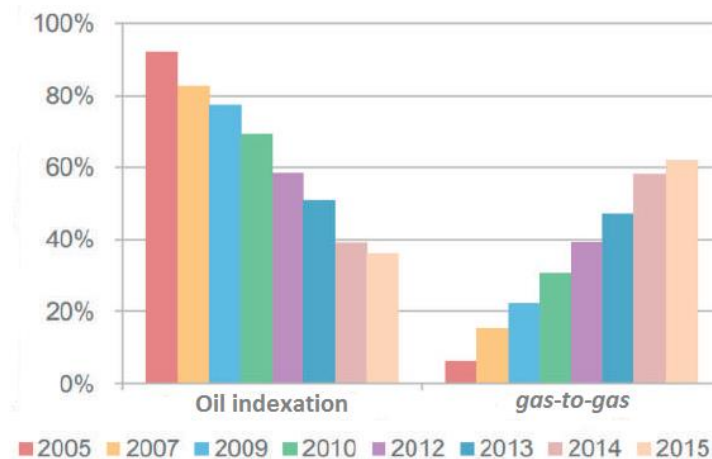


Figure 71: Worldwide evolution of the mechanisms for fixing the price of natural gas [33]

The expansion of LNG market has been one of the reasons for this change, with low transport costs that enable responding to demand needs in the short term. The IEA forecasts indicate that 90% of the projected growth in global NG trade will be covered by LNG, increasing its share from 39% to 59% between 2016 and 2040 [17]. This fact, together with the expected growth in LNG exports by the USA, will promote greater integration among the different regional markets, which in turn will result in a convergence of prices at a global level [33].

European market

Forecasts indicate that the demand of NG in Europe will follow a similar trend shown in recent years (see Figure 72), remaining stable until 2022, mainly due to the expansion of renewable energies in the electricity and industrial sector, as well as to the measures around energy efficiency. In the long term, however, a decrease in consumption of 200 Mtoe is expected in the period 2016-2040, as a result of the energy transition to an economy with lower CO₂ emissions [33].

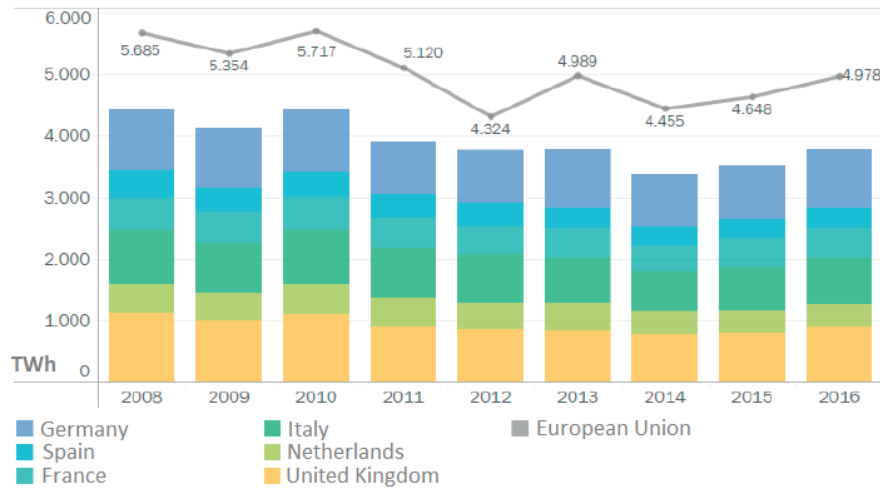


Figure 72: Evolution of natural gas consumption in Europe [33]

In 2016, the consumption of NG reached 4978 TWh in the EU, of which only 27% was autochthonous production [33]. Approximately 90% of imports were supplied via pipeline, whereas the remaining 10% was supplied by LNG deliveries [33]. In this context of high energy dependence, moreover, the EU suffers from a shortage in the diversification of supplies: Russia (40%), Norway (28%), Qatar (7%) and Algeria (5%) [33].

In order to improve this situation, in the last decades EU has promoted an international energy market which facilitates a cross-border trade in NG, thereby improving the efficiency and competitiveness of prices and, ultimately, improving the security of supply [33]. The aim of what is called the *Gas Target Model* has consisted, thus, in the creation of national *hubs* in which a liquid spot market and a future market are developed. Likewise, the market areas defined by the *hubs* are interconnected, so as to promote exchanges between gas systems based on their necessity [33]. Figure 73 shows the main European *hubs*, as well as their date of creation.

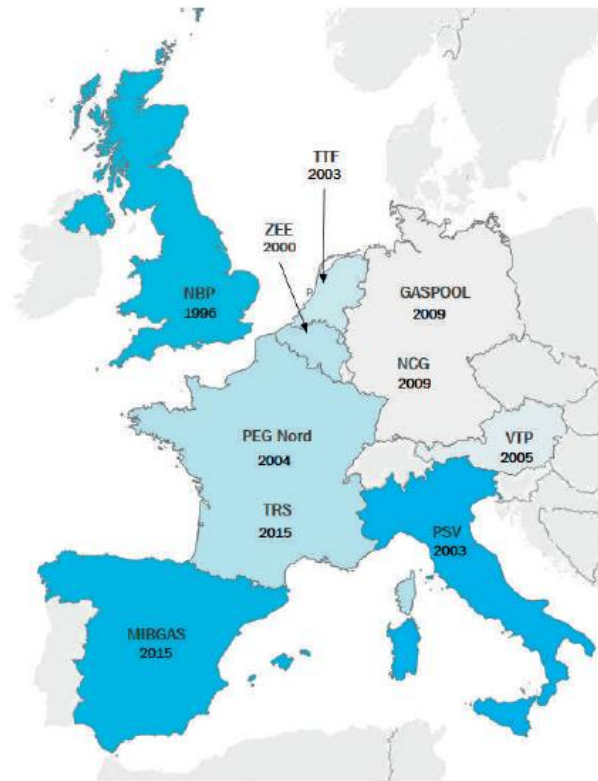


Figure 73: Main European hubs and their creation date [33]

However, as mentioned above, there are significant differences between the different *hubs*, and although the European market can be considered a mature market, in terms of liquidity only the *hubs* NBP (Net Balancing Point) and TTF (Title Transfer Facility) meet the needs of the agents participating in the market [33].

Regarding geographical differences, in the Northwest Region of Europe there is a high level of competition among NG suppliers, and their offers are mainly carried out by spot deliveries or by *gas-to-gas* contracts that include flexibility clauses. As a result, the different *hubs* in North and Central Europe present a high level of price convergence. In the market of Southern Europe, on the contrary, LNG has a greater predominance, and there is a greater dependence on imports of NG from North Africa with prices indexed to the oil price [33].

Iberian gas market MIBGAS

The Spanish gas system is the sixth most important in the European Union regarding the volume of consumed natural gas. Its autochthonous production barely covers 0.21% of the total national demand, and both its storage capacity and the capacity for imports through interconnections with adjacent systems (Algeria, France and Portugal) are limited. However, thanks to the diversification of its infrastructures, the Spanish gas system has a considerable flexibility [33].

As it can be seen in Figure 74, LNG has had an important role as a source of supply, unlike European gas systems, in which most of the supply is carried out through gas pipelines [33]. Regarding supplying countries in 2017, Algeria is the main supplier with a percentage of 48.3%, followed by Nigeria (12.5%), Peru (10.1%), Norway (10%) and Qatar (10%) [37].

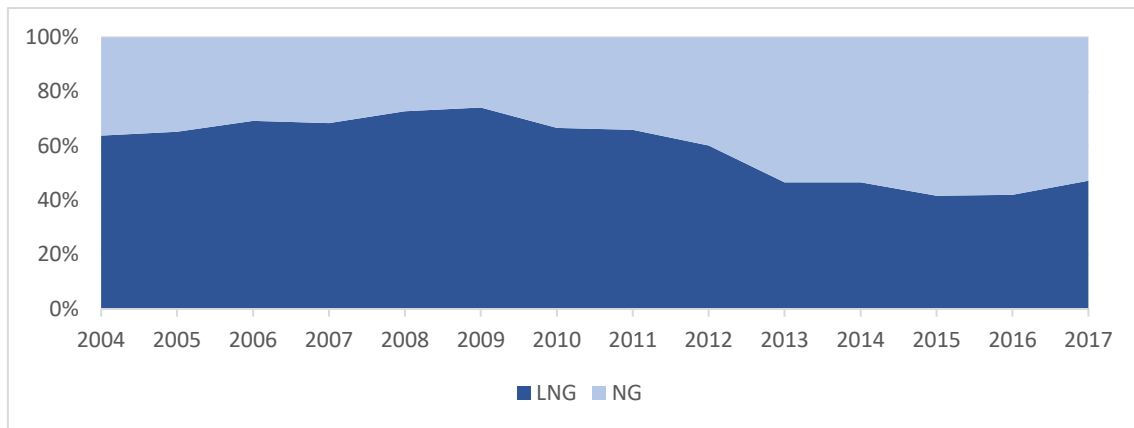


Figure 74: Supply of natural gas to the Spanish gas system (Co-adapted from [37])

The entry into operation of the Organized Gas Market in Spain occurred relatively late, in December 2015, after the entry into force of Law 8/2015, of May 21 [33]. As a result, the Spanish *hub* is currently considered an emerging market within both the volume of NG traded, the number of agents involved and the level of liquidity, in general, are considerably reduced [33]. In 2017, for example, only 13,376 *GWh* were negotiated, that is, 3.8% of the total national demand, which suggests that, compared to the OTC market, agents usually use the Organized Market to balance and adjust their portfolios in the very short term [33].

Among the barriers that currently prevent a greater integration of the Iberian Gas Market MIBGAS, it is worth mentioning the limited capacity of interconnection with the South of France (TRS) and the high interconnection tolls from France to Spain compared to those corresponding to the Northwest Region of Europe. These explain to a large extent the reasons for a structural price difference between MIBGAS and the reference *hubs* in Northern Europe (in 2017, the average spread value of the D+1 product between MIBGAS and TTF was 3,44 €/MWh) [33].

Likewise, except for the NG injected from France, which around 10% of the total, the supply of the Spanish gas system is carried out mainly from Algeria (long-term contracts, with little flexibility and prices indexed to oil) and through LNG, whose delivery prices are strongly linked to the fluctuations of the Asian market. All this reduces competition among the bidders, having as a result a negative impact on prices [33].

Figure 75 shows a comparison of the evolution of the price in NBP and NG supply costs recorded in Spanish customs, which has historically been higher than the ones registered in the British *hub* [47] [37].

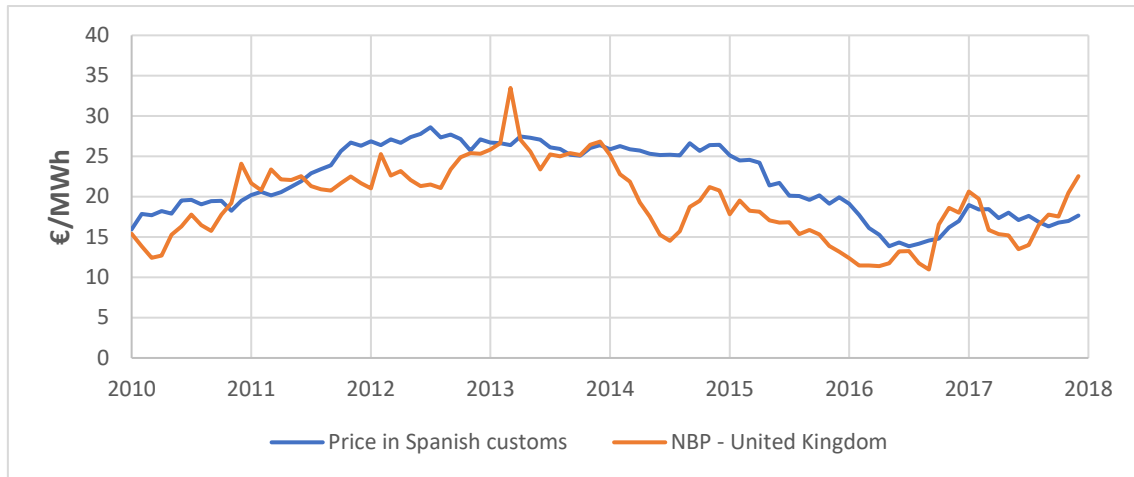


Figure 75: Price of natural gas in NBP and Spanish customs, 2010-2017 (Co-adapted from [47] [37])

It should be noted, however, the spot price signals offered by MIBGAS during 2017 have been very representative, reflecting adequately the dynamics of NG supply and demand. Figure 76 shows how, despite a general spread throughout the year, prices in MIBGAS have followed a similar evolution to that of other European hubs. At as exception, it is worth highlighting the decoupling suffered in January (in MIBGAS and TRS), which was clearly due to circumstantial reasons, such as winter temperatures and an energy shortage in France caused by the unavailability of its nuclear park [33].

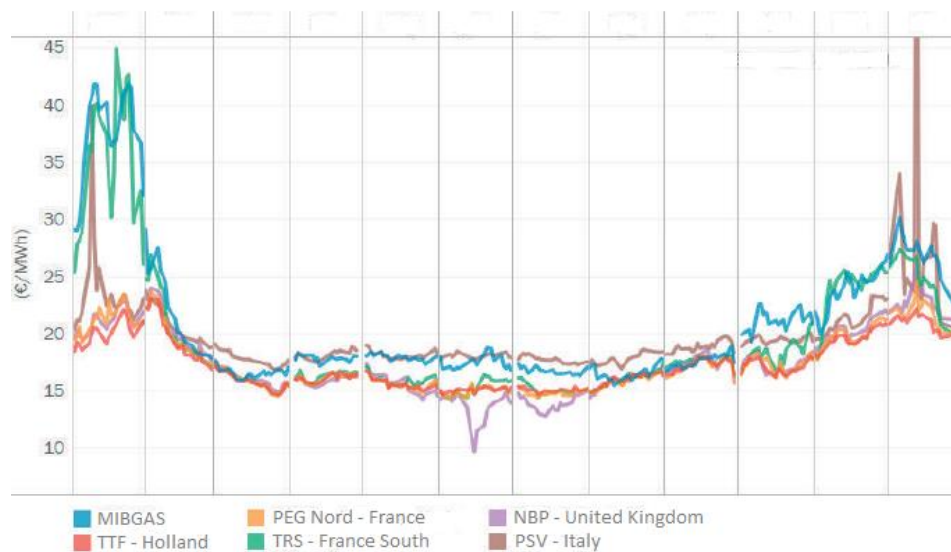


Figure 76: Evolution of the D+1 price during 2017 in the main European hubs [33]

The NG negotiated in MIBGAS is supplied, on the one hand, by the inelastic supply to the price, which includes the imports from Algeria and, to a lesser extent, from France, as well as the regasification of the LNG carried out depending on the demand. On the other hand, various sources of flexibility are available, such as additional regasification, additional supply from Algeria, spot imports from the TRS area and natural gas extractions from underground storage facilities. These are the ones which determine the marginal price of the product MIBGAS D+1

(daily product), as a result of the interaction between marginal supply and marginal demand in the short term [33].

In general, the evolution of the price MIBGAS D+1 has responded, in the last years, to the Fundamental Factors of supply and demand. On the supply side, the price has been correlated with the level of underground storage tanks and LNG tanks, the level of regasification and extraction of NG, as well as the storage in gas pipelines (*linepack*) [33].

On the part of the demand, conversely, the temperature has been the main inductor of the dynamics of the spot price of NG in Spain, as it has a significant influence on total fuel consumption. Figure 77 shows the relationship between the MIBGAS D+1 price and the demand for NG throughout the year, both for conventional use and for electricity generation.

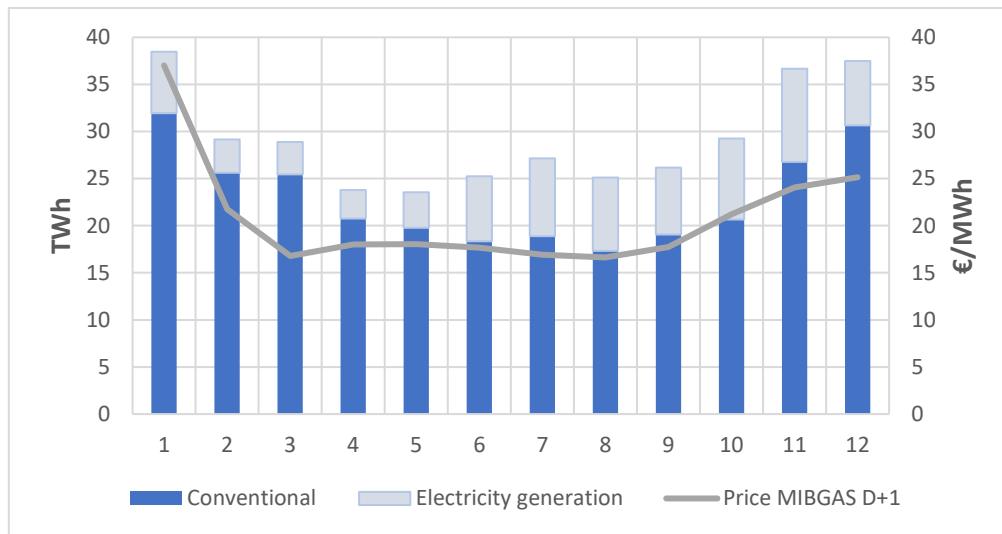


Figure 77: Price MIBGAS D+1 and natural gas consumption during 2017 (Co-adapted from [33] [37])

Forecasts of the price of natural gas

The current situation of high availability and relative abundance of gas, thanks mainly to the expansion of the LNG market, will probably continue until 2023, when the Fundamentals of the offer should encourage the recovery of the price of NG in the international markets, reaching in 2035 the levels registered in 2010 [33].

In the long term, it is expected that the decoupling between NG and oil will be accentuated in the European and Asian markets, as a result of which the price of oil will no longer be a reference for the price of NG [51]. The increase in LNG exports, on the other hand, will lead to a greater convergence of prices in the different regional markets, increasing competition and exerting a downward pressure on the prices of NG [51].

However, given the complexity of the markets and the innumerable factors that influence the price of NG, the previously forecasts values will be taken as a reference, that is a stable price until 2023 around 17 €/MWh (average of the cost of supply registered in the last year in the Spanish custom) and a linear increase until 2035, when the price reach 27 €/MWh (average price in the year 2010) [33] [37]. Figure 78 shows the forward curve of the price of NG that will be considered in the present work for the period 2020-2050.

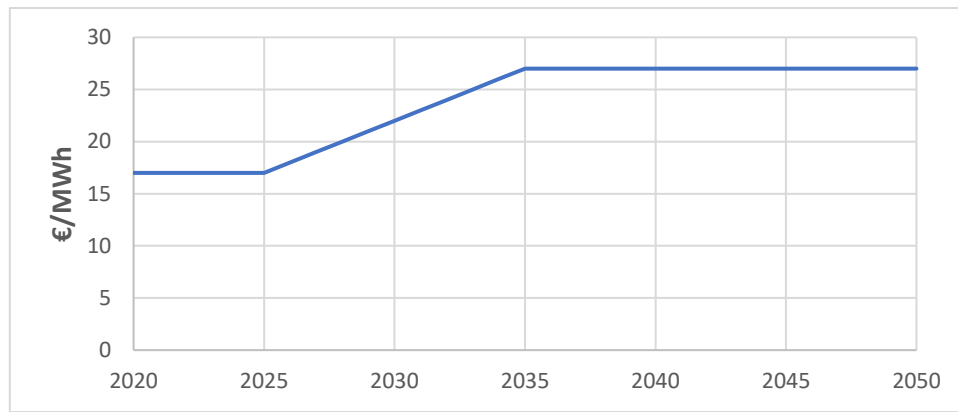


Figure 78: Natural gas Price forward curve, 2020-2050

3.2.3.3.- Coal

As shown in Figure 79, autochthonous coal production in Spain has fallen considerably in the last decade, at an average rate of 23% per year, going from 8430 *kton* in 2010 to 1742 *kton* in 2016 [40]. This is a result, on the one hand, of the difficulty of competing with large exporters such as Colombia, Russia, Indonesia or South Africa, which constituted 87% of coal imports in Spain in 2017. On the other hand, the progressive closure of non-competitive coal mines accorded in Decision 2010/787/EU of 10 December has caused a progressive decrease in the autochthonous coal production [40].

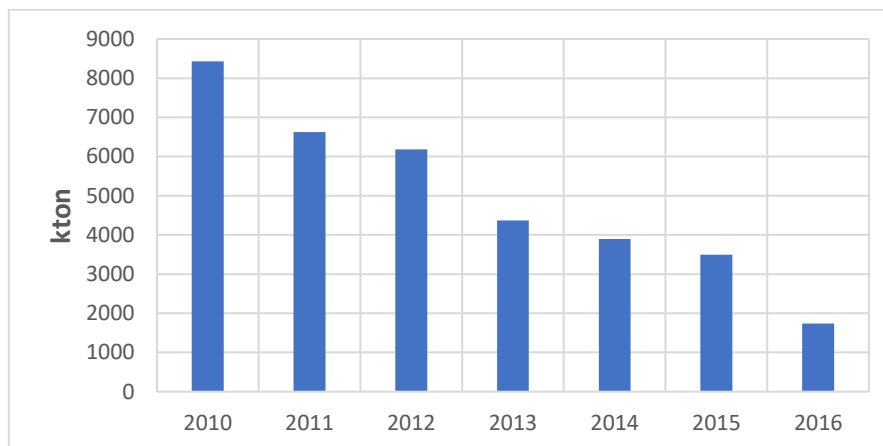


Figure 79: Evolution of autochthonous coal production in Spain, 2010-2016 (Co-adapted from [40])

Given the abundance of coal reserves and the reduced capital costs of mine development compared to other fossil fuels, the variable cost of production and transport is a key factor in the formation of the price of the coal [40]. Taking into account, likewise, the presence of oil along the entire coal supply value chain, the evolution of oil prices affects the costs of coal and, therefore, its price in the markets [40].

Figure 80 shows the evolution of the prices of South African and Colombian coal, considered as the most representative in the cost of Spanish supply, as well as the price of Brent petroleum in the last decade. Although the prices of both commodities have a certain relationship, it is not as

clear as in the case of NG. This is due to the fact that, depending on the type of mines and the transport used, the price of coal may have a greater or lesser exposure to the price of oil [15].

As of 2012, above all, there is a clear decoupling between the prices of coal and Brent oil, a fact that is being reversed since 2016, apparently, owing to a generalized rise in the main energy products [50]. According to the IEA, the fall suffered in the period 2012-2016 was due to an overcapacity of coal in the market, as a result of investments in mines carried out between 2007 and 2011 in a context of high demand for coal [15]. From 2012, however, demand has been falling gradually, mainly due to the progressive penetration of renewable energies and the downward pressures exerted by environmental regulation [50].

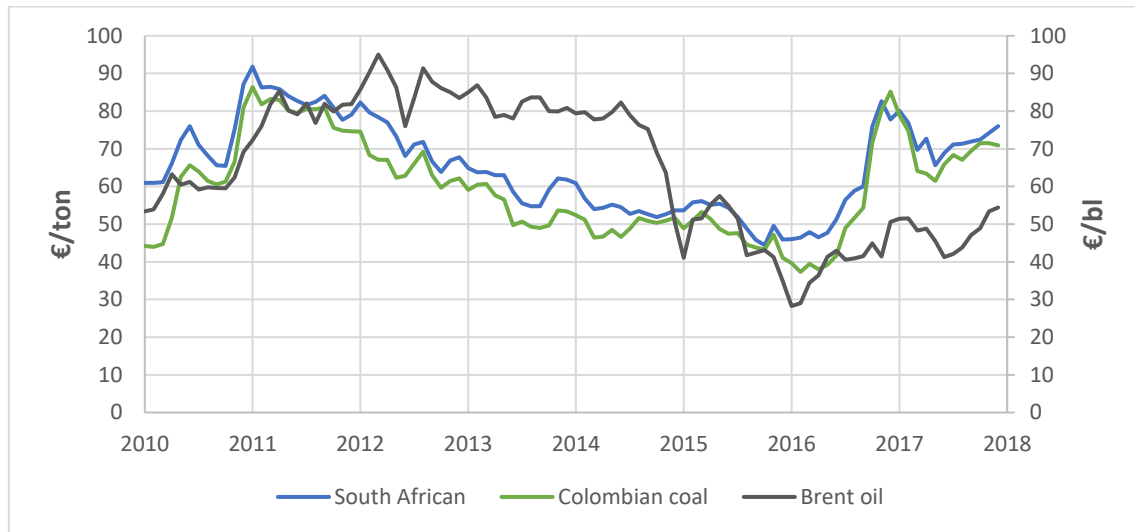


Figure 80: Evolution of South African and Colombian coal (left) and Brent oil (right) prices, 2010-2017 (Co-adapted from [46] [36])

International coal markets connect different regional markets through imports, exports and price fluctuations. Price differences, however, can be considerable between them, as a result of transport costs or the quality of the product [15].

In general, the price of coal in the international markets is determined by Australian, Russian and US mines. Forecasts estimate that the balance between the supply and demand of coal in international markets will have been recovered by 2020, which will put upward pressure on the price of coal. This recovery is being seen from 2016 until today (see Figure 80), a period in which the average price has gone from 43 €/ton in January 2016 to 73 €/ton in December 2017 [36].

Long-term forecast realized by the IEA in World Energy Outlook 2015 predicted a general rise in prices, with important differences however between the different markets. In the United States, for example, the price of coal is expected to reach 70 \$/ton in 2040, compared to 60 \$/ton in 2014, whereas the forecasts for 2040 in India and China point to values of 90 \$/ton and 110 \$/ton, respectively, compared to 65 \$/ton and 90 \$/ton in 2014 [15].

Due to significant price differences between the markets, the expected growth for 2040 in relation to 2014 values will be taken into account, that is, 16.67 % in United States, 38.46% in India and 22,22% in China. Considering a growth equal to the arithmetic mean between the

three values, the price of coal in Spain would reach in 2040 an approximate value of 67 €/ton, which very close to the 70 €/ton registered in 2017. Therefore, it is assumed that the recovery of the price of coal has already happened and a constant price of 70 €/ton will be considered for the period 2020-2050 [15].

3.2.3.4.- Uranium

Finally, despite the significant fluctuations that have occurred in the last decade in the price of uranium (U_3O_8), the sensitivity of this market to the fluctuations of the main energy commodities is lower (see Figure 81). Likewise, compared to fossil fuels, the price of uranium exerts a lower influence on the variable costs of the nuclear power plants. Therefore, in order to simplify the analysis, a constant price will be considered for the period 2020-2050, equal to the average price registered in the last 8 years, which amounts approximately to 30 €/ton U_3O_8 [51].

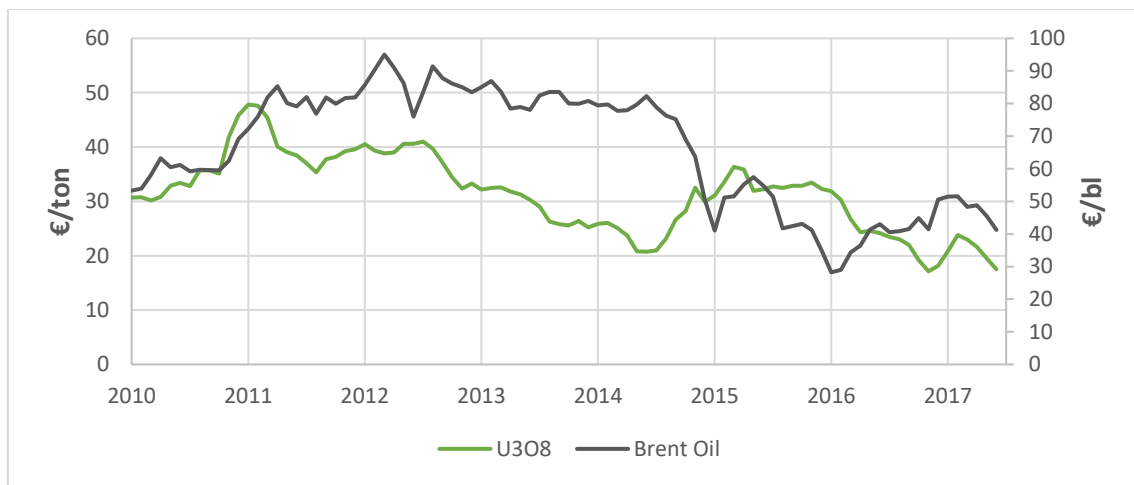


Figure 81: Evolution of U_3O_8 price (left) and Brent Oil price (right), 2010-2017 (Co-adapted from [46] [51])

3.2.3.5.- Electricity in the daily market

Thus, the forecasts of the marginal price of electricity in the daily market will be based on the model developed previously, according to which the price will depend on the following factors:

- The amount of electricity generated each month by each technology.
- The weight of each technology, by which it is possible to estimate the importance of each technology in the matching process.
- The variable costs of production of each technology.

The forecasts of electricity generation for each technology have been calculated in Section 3.1, determining the contribution of each technology in the generator mix for each month of the period 2020-2050. The weights associated with each technology, on the other hand, have been calculated in this Section, whose values are included in Table 9. Finally, the variable costs of each technology have been determined for each month of the period 2020-2050, based on the forecasts of the price of the fuels and CO_2 emission rights.

Figure 82 shows the forward curve of the marginal price of electricity in the daily market for each month of the period 2020-2050. It can be seen how between 2020 and 2035 the seasonal

sensitivity of the price increases considerably, which is a result of the increase of the share of CCGT in the electric mix, on the one hand, and the progressive increase of the price of CO_2 emission rights, on the other. According to this seasonality, between January and May the prices suffer a significant drop, due to the greater renewable generation, while the maximum prices are reached between September and October, as a result of a greater generation of CCGTs.

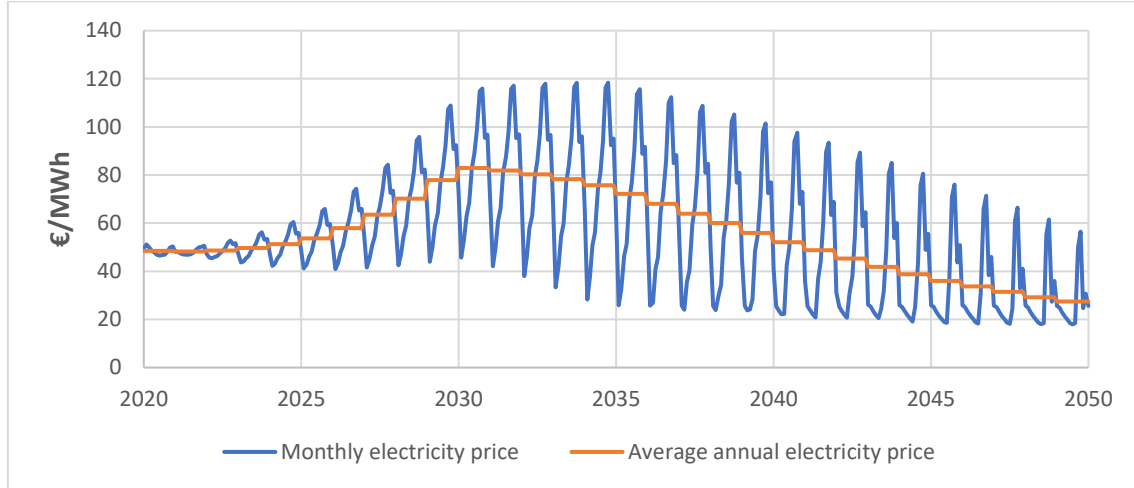


Figure 82: Monthly marginal price of electricity in the daily market (blue) and average annual marginal price (orange)

Regarding average annual values, an increase of almost 70% is expected for the marginal price in the daily market, going from 49 €/MWh in 2020 to 83 €/MWh in 2030. On the one hand, due to the progressive closure of conventional thermal power plants between 2020 and 2030, the thermal gap is occupied by CCGTs, as a result of which its share in the generator mix is not reduced, despite the increase of renewable generation in this period. On the other, the variable costs of CCGTs increase by 70% between 2020 and 2030, from 46.55 €/MWh to 62.59 €/MWh, resulting in the increase of the price of electricity mentioned above.

In the long-term, nevertheless, the marginal price is expected to decrease, due to the massive entry of renewables in the matching process. According to the estimations carried out, the price will reach an average value of 27 €/MWh, which represents 45% of the price perceived in 2020.

4.- ECONOMIC ANALYSIS OF SOLAR PV AND CCGT PLANTS

4.1.- Generation forecasts of a solar PV plant in Spain

4.1.1.- Location

Before making an investment decision, it is necessary to consider the different factors that will affect the performance of the plant, as well as construction and development costs. The available solar irradiance is the most important variable, as it influences directly the efficiency of the solar power plant [52]. Figure 83 shows the average global horizontal radiation registered in Spain during the period 2004-2010. The circle indicates the region where maximum values were achieved. Therefore, the search of a suitable location will be focused on this particular area.

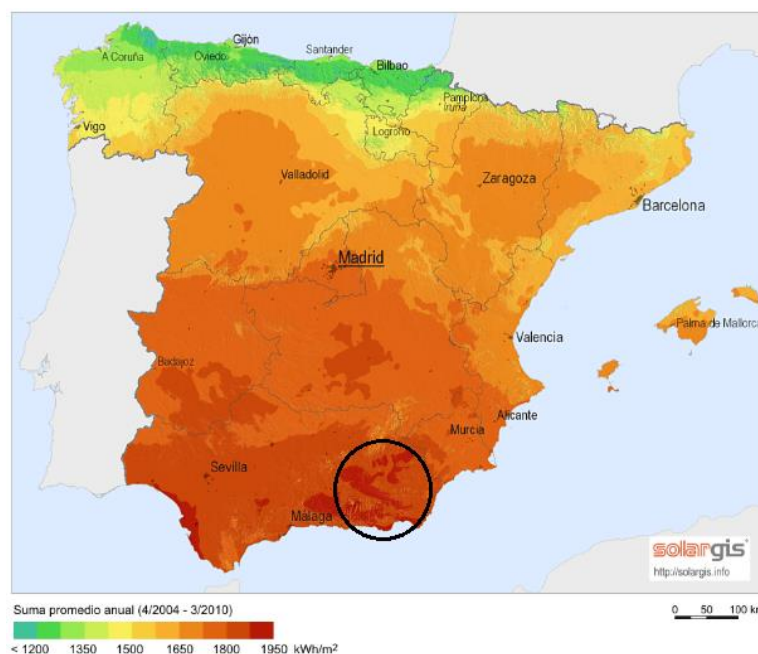


Figure 83: Global horizontal radiation in Spain in the period 2004-2010 (Co-adapted from [53])

When placing an electricity generation facility, it is also important to consider the proximity of the grid transmission lines, given the investment required for their construction. Therefore, the PV solar plant should be located in an area next to them, so that the energy generated can be easily evacuated [52]. Figure 84 shows the main transmission lines in the selected area. Here a further selection has been carried out, based on the proximity of a 220 V transmission line. The flatness of the region has also been considered, which is essential for both solar exposure and constructability [52].

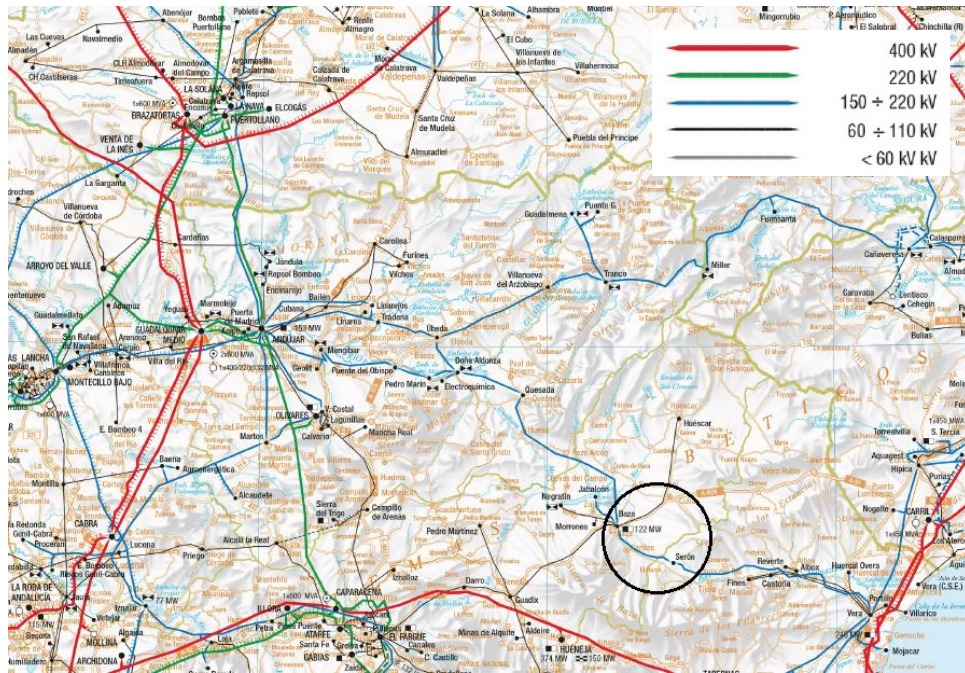


Figure 84: Main transmission lines in the selected area (Co-adapted from [54])

In order to select the specific site, finally, available unoccupied lands near to highways have been searched, so that road construction activities are reduced as much as possible. Figure 85 shows the selected specific site ($\varphi = 37.52^\circ$; $\Lambda = -2.75^\circ$), which is near to Baza, a city located in the province of Granada, Andalusia.



Figure 85: Location of the PV plant (Co-adapted from [55])

4.1.2.- Calculation of the forecasts by MATLAB

In this location, the global annual horizontal irradiation takes an average value of $H = 1849 \text{ kWh/m}^2 \cdot a$, which has been calculated from the monthly average global horizontal irradiations provided by ADRASE [35]. As neither direct nor diffuse irradiations were given, it has been assumed that direct irradiation is proportional to the percentage of clear days per month

[34]. Figure 86 shows the variation of the average global horizontal irradiation over the year, as well as the weight of direct and diffuse irradiances in each month:

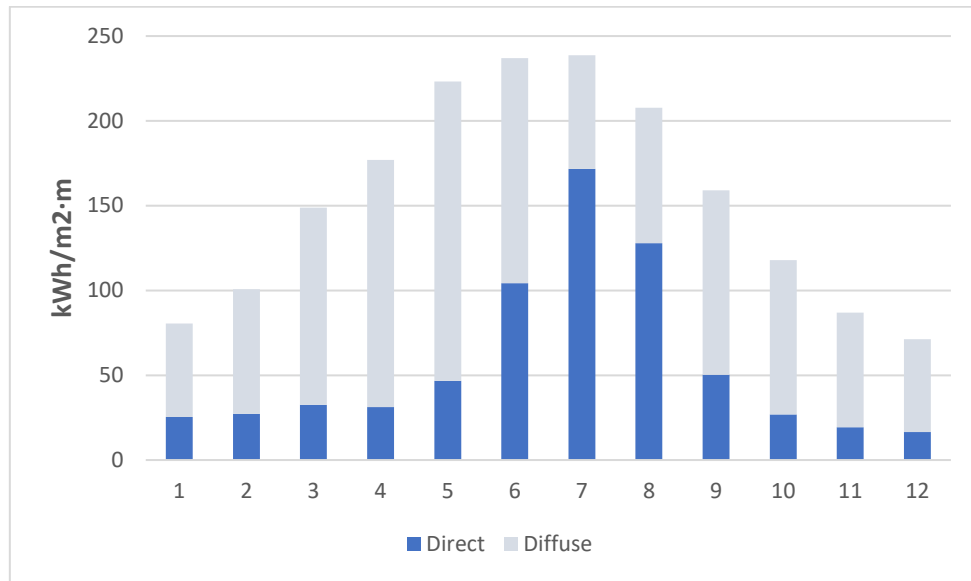


Figure 86: Average global horizontal irradiation

In order to know the position of the Sun each hour of each day of a year, two matrixes have been defined so as to take the values of Sun altitude γ_s and solar azimuth α_s , respectively. They will both have 365 columns, one for each day of the year, as well as 16 rows, according to the variation of the local solar time from 05:00 to 20:00.

Knowing the longitude Λ of the location and taking into account that Spain is in the Central European Time zone, that is, $TZ = +1$, Eq. 15 gives a deviation of 1.18 hours, which means that solar noon happens at 13:10. As the products negotiated in the wholesale market are correlated with the hours of the day, a deviation of 1 hour is assumed, so that solar noon is considered at 13:00.

In addition to this, in order to make calculations simpler, γ_s and α_s of every 15th day of each month have been considered as the average position of the Sun in each month of the year. As an example, Figure 87 shows the values of γ_s and α_s for December, February, March, April and June:

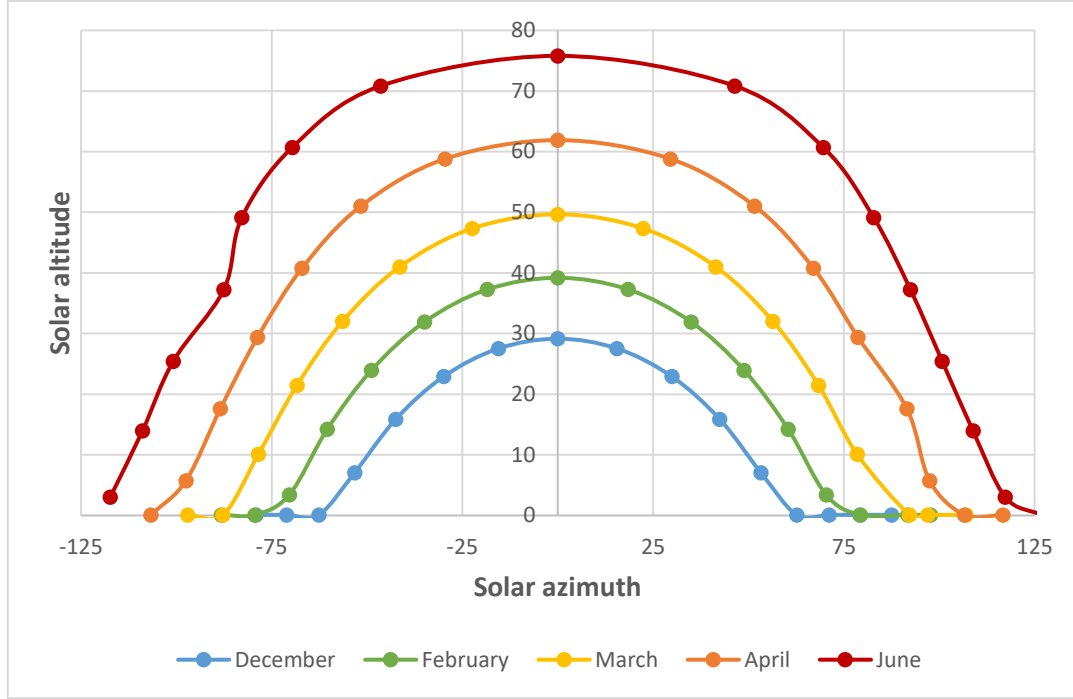


Figure 87: Solar altitude and Sun azimuth in the standard time of Spain

In order to determine the global horizontal irradiation for each hour of a day during a month, it has been assumed that it is proportional to the square of the height of the Sun in the sky. Hence, as the height is proportional to the sine of the solar altitude γ_s , the variation of the radiation during the day can be approximated as follows:

$$H_{mn} = H_m \cdot \frac{\sin^2(\gamma_{s_{mn}})}{\sum_{i=1}^h \sin^2(\gamma_{s_{mn}})} \quad [Eq. 57]$$

Where,

- m : month.
- n : hour.
- $\gamma_{s_{mn}}$: solar altitude for each hour of each month.
- H_m : irradiation in a month.
- H_{mn} : irradiation in each hour during a month.

The approximation made can be observed in Figure 88, which shows the global horizontal irradiation registered in each hour during the month of July, as well as the contribution of direct and diffuse irradiances:

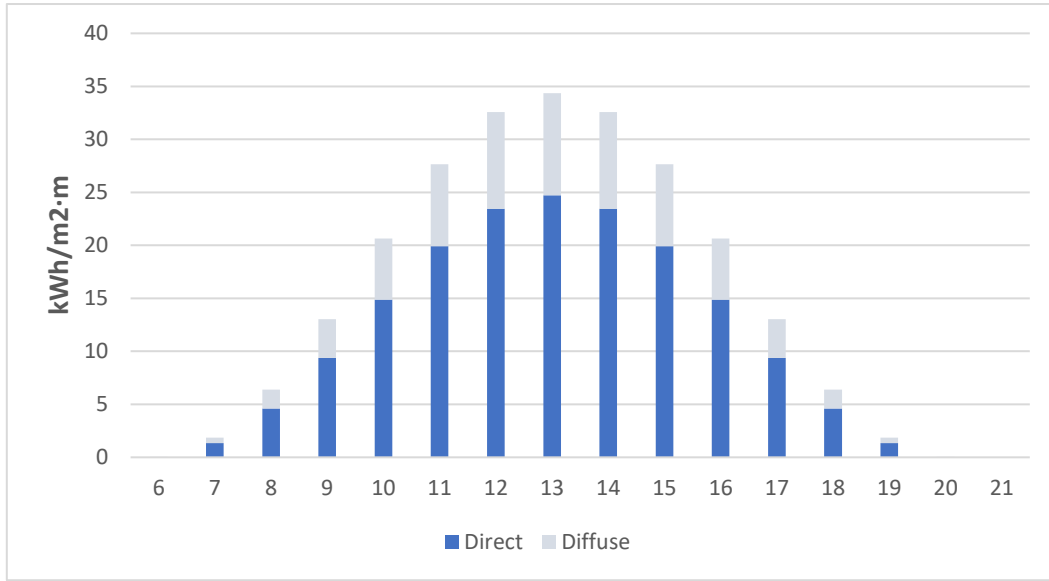


Figure 88: Global horizontal irradiation (direct and diffuse) each hour during the month of May

Once direct and diffuse horizontal radiations are known for each hour of each month of the year, the modules' tilt can be optimized so that total radiation taken up by them is maximized. For that purpose, an algorithm has been developed in MATLAB, which optimizes the inclination angle of the modules in order to maximize the total irradiation taken up by the modules over the year, that is, Eq. 4. Figure 89 shows the dependence of the total irradiation on the generators angle. As it can be appreciated, the optimum angle happens to be $\beta = 34^\circ$, by which a total annual irradiation of $H = 2071 \text{ kWh/m}^2 \cdot a$ is achieved.

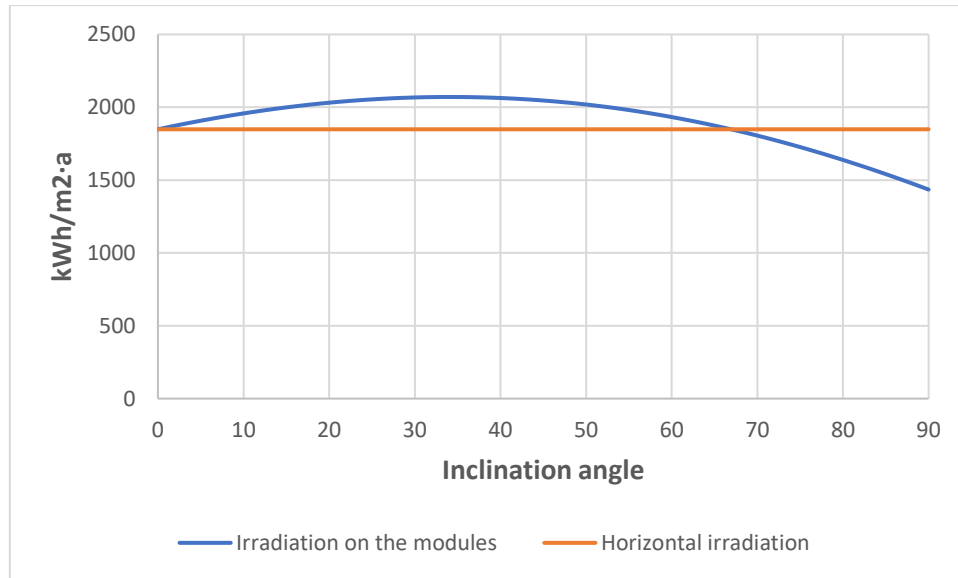


Figure 89: Dependence of the irradiation on the inclination angle of the modules

JINKO SOLAR has been selected as the manufacturer for the solar modules, which is recognized for having a good quality/price relation [56]. The model selected, in this case, is JKM265P [57], a 265W polycrystalline solar panel, whose specifications are included in the Table 10. It has been also assumed an efficiency of $\eta_{inv} = 95\%$ in the inverters needed to transform the DC current into AC current.

JKM265P		
	STC	NOCT
P_{MPP}	265 W_p	197 W_p
V_{MPP}	31,4 V	29 V
I_{MPP}	8,44 A	6,78 A
V_{OC}	38,6 V	35,3 V
I_{SC}	9,03 A	7,36 A
$TC(P_{MPP})$	−0,41 %/°C	
$TC(V_{OC})$	−0,31 %/°C	
$TC(I_{SC})$	−0,06 %/°C	
NOCT	45 °C	
η	16.19%	

Table 30: Specifications of the model JKM265P

In order to calculate the number of modules $N_{modules}$ needed for a certain capacity of the plant P_{plant} , the maximum power point is used:

$$N_{modules} = \frac{P_{plant}[MW] \cdot 10^6}{P_{MPP}(STC)} [Eq. 58]$$

Assuming a capacity of $P_{plant} = 50 MW$, therefore, 188,680 modules will be needed. In order to calculate the electricity generated by these modules, however, temperature in the cells T_{cell} need to be determined for each hour of each month. This temperature depends on the ambient temperature T_a and the solar radiation E_{total} , as explained in the Eq. 25.

The total radiation in the modules for each hour of each month E_{total} can be easily calculated, dividing the irradiation in each hour during a month by the number of days in each month. Conversely, the only data achieved for the ambient temperature in the selected region contains average values of mean temperature T_m , maximum temperature T_{max} and minimum temperature T_{min} in each month of the year [34].

Therefore, in order to determine T_a each hour in each month, it has been assumed that T_a changes sinusoidally around the mean value T_m , with an amplitude equal to the half of the difference between maximum and minimum values T_{max} and T_{min} . The temporal lag has been set so that the maximum temperature is achieved at $t = 14:00$.

$$T_a = T_m + \frac{T_{max} - T_{min}}{2} \cdot \sin\left(\frac{\pi}{12}t - \frac{2\pi}{3}\right) [Eq. 59]$$

As an example, Figure 90 shows the hourly ambient temperature in January, April and July:

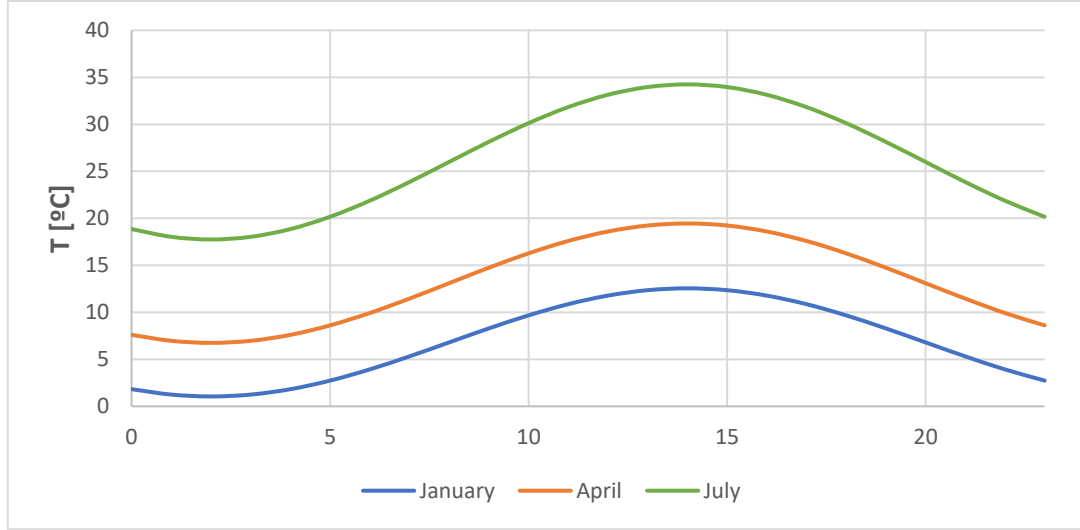


Figure 90: Variation of ambient temperature during a day in January, April and July

Once having calculated T_a for each hour of each month, temperature cell T_{cell} have been determined with the Eq. 25. Likewise, P_{MPP} depends on T_{cell} , that is, the output of the solar modules is affected by their temperature. This relation is given by the Eq. 26. As an example, Figure 91 shows the average values of ambient temperature T_a , cell temperature T_{cell} and the peak power of the modules P_{MPP} , during a day of June.

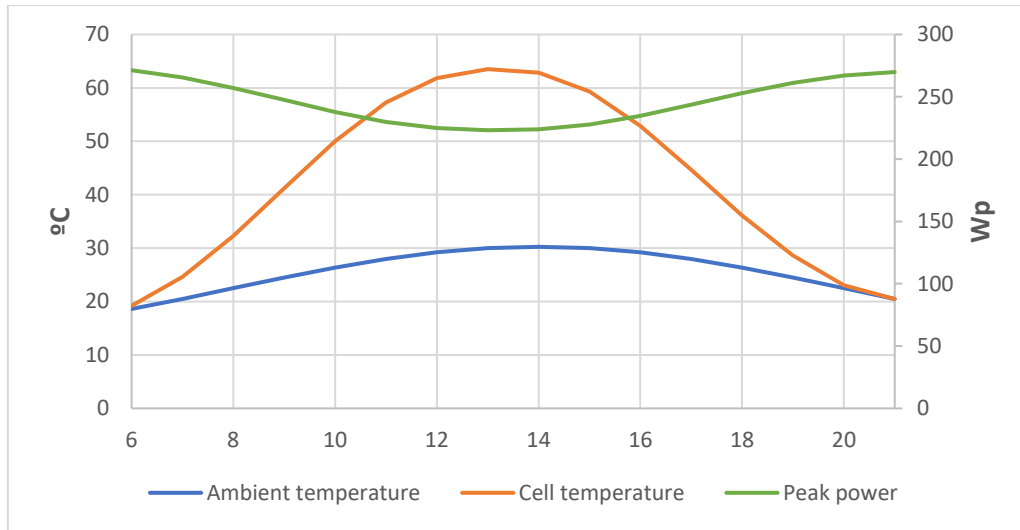


Figure 91: Evolution of ambient temperature (left), cell temperature (left) and peak power (right) during a day in June

Hence, it can be finally calculated the electricity generated by the modules each hour of each month. The hours that have been considered go from 6:00 to 21:00, which is the time zone in which there is solar radiation. The sum of all the electricity generated during the months represents the annual electricity generation of the plant G_{annual} :

$$G_{annual} = N_{modules} \cdot \eta_{inv} \cdot 10^{-6} \cdot \sum_{i=1}^{12} \sum_{j=6}^{20} \frac{P_{MPPij}}{E_{STC}} \cdot H_{ij} [GWh] [Eq. 60]$$

According to the model developed in MATLAB, the PV plant would have an annual electricity generation of $G_{annual} = 90.33 \text{ GWh}$, which implies a load factor of $f_{load} = 20.62\%$. In order to have an idea of the weight of each month and each hour in the total output of the plant, Figures 92 and 93 shows, respectively, the electricity generation by month and its evolution during a single day of December and July.

In the month of July, the production reaches a maximum value of 11.6 GWh , whereas December turns out to be the month where less electricity is generated, with an output of 4.1 GWh . Figure 93 shows, on the other hand, that in December the solar PV power generation plant works between 09:00 and 17:00, whereas in July it covers a wider period, between 06:00 and 20:00.

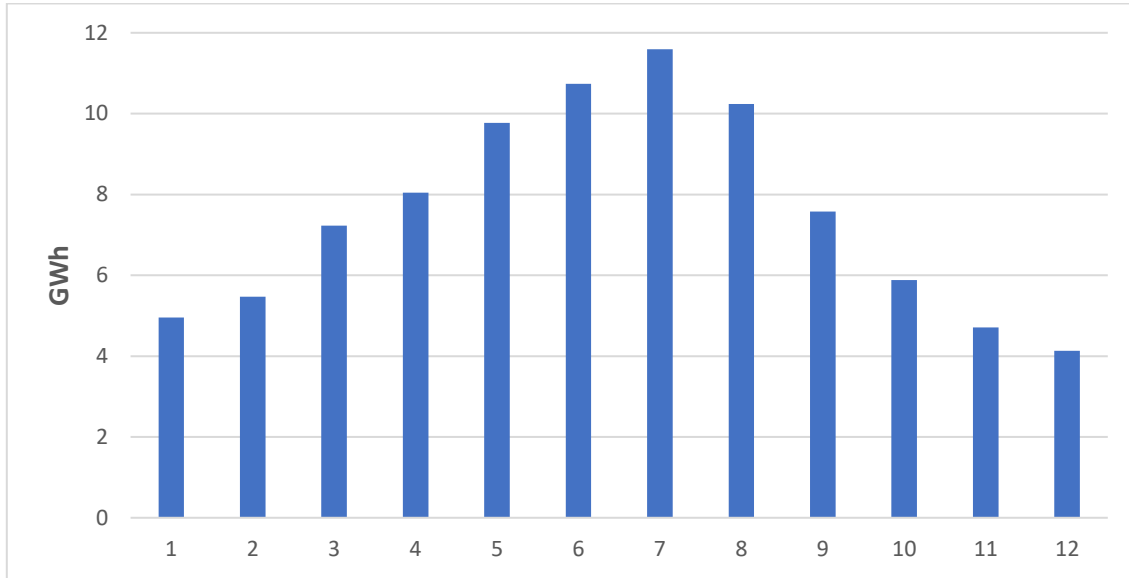


Figure 92: Average electricity generation by month

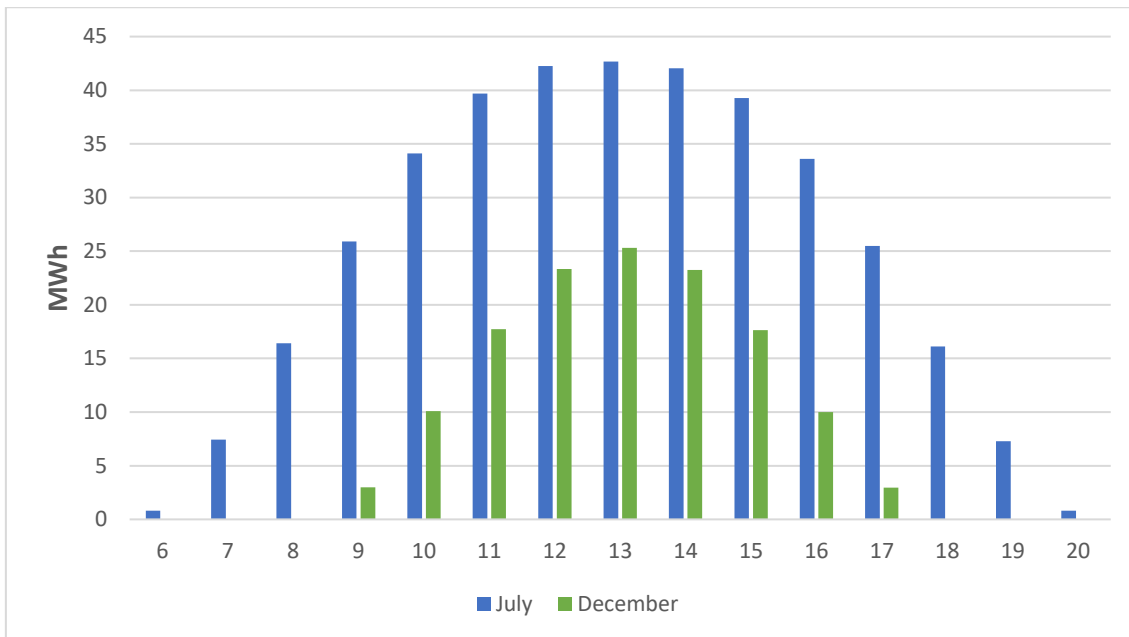


Figure 93: Average electricity generation by hour in December and July

4.1.3.- Validation with SOLAR PV

In order to verify that the results obtained by the model developed in MATLAB are reliable, they have been validated by the software SOLAR PV. A model has been developed by this program, having as inputs the location of the PV plant (the city of Baza), as well as the manufacturer and the model of the modules, that is, the module JKM265P made by Jinko Solar. Table 11 shows the main results achieved by SOLAR PV compared to the ones obtained by MATLAB and includes the deviation of the former in relation to the latter.

	MATLAB	SOLAR PV	Deviation
Horizontal irradiance	1849 $kWh/m^2 \cdot a$	1975 $kWh/m^2 \cdot a$	6.4%
Inclination angle	34°	32°	-5.9%
Irradiance onto tilted module	2071 $kWh/m^2 \cdot a$	2231 $kWh/m^2 \cdot a$	7.7%
Electricity generation	90.33 GWh	97.48 GWh	7.9%
Load factor	20.6%	22.3%	7.9%

Table 11: Comparison of the main results obtained by MATLAB and SOLAR PV

The production forecasts calculated by SOLAR PV amount to 97.48 GWh , 7.9% higher than the 90.33 GWh predicted by the model developed in MATLAB. However, it should be noted that the horizontal radiation obtained from the database of SOLAR PV is 6.4% higher than the radiation on which the model of MATLAB is based. This difference could be a result of the number of years that has been considered in order to calculate the average values. Indeed, the average irradiance taken into account in MATLAB is the average of the values registered during the period 2004-2010, whereas SOLAR PV has a wider database that covers the period 1991-2010.

The difference between the production forecasts of both model is partially explained, thus, by the difference of the starting data. Figure 94 shows the monthly average radiation for both models. It can be seen that in the model developed by SOLAR PV the radiation throughout months results, in general, higher than the radiation values considered in MATLAB.

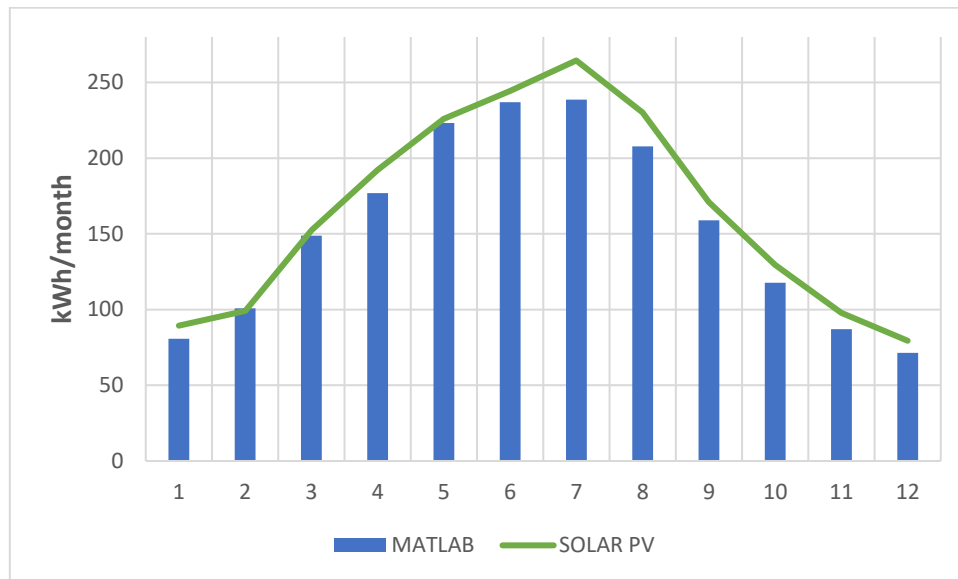


Figure 94: Monthly average radiation in MATLAB and SOLAR PV

The inclination angle of the modules determined in MATLAB, on the other hand, is greater than the one calculated in SOLAR PV. The assumption that could have caused this deviation is the one related to the share of direct and diffuse irradiation in the global horizontal irradiation. According to this assumption, direct irradiation is proportional to the percentage of clear days per month, so that it accounts for 37% of the total irradiation, in contrast with 63% of diffuse radiation.

Additionally, the average position of the sun in each month of the year has been assumed to be equal to the position registered every 15th day of each month. This assumption could have also influenced on the final result of the inclination angle. Figure 95 shows the irradiance onto the tilted modules in both MATLAB and SOLAR PV models. It can be seen that between May and August the irradiance results higher in the model developed in MATLAB, whereas the rest of the year the model in SOLAR PV shows higher values.

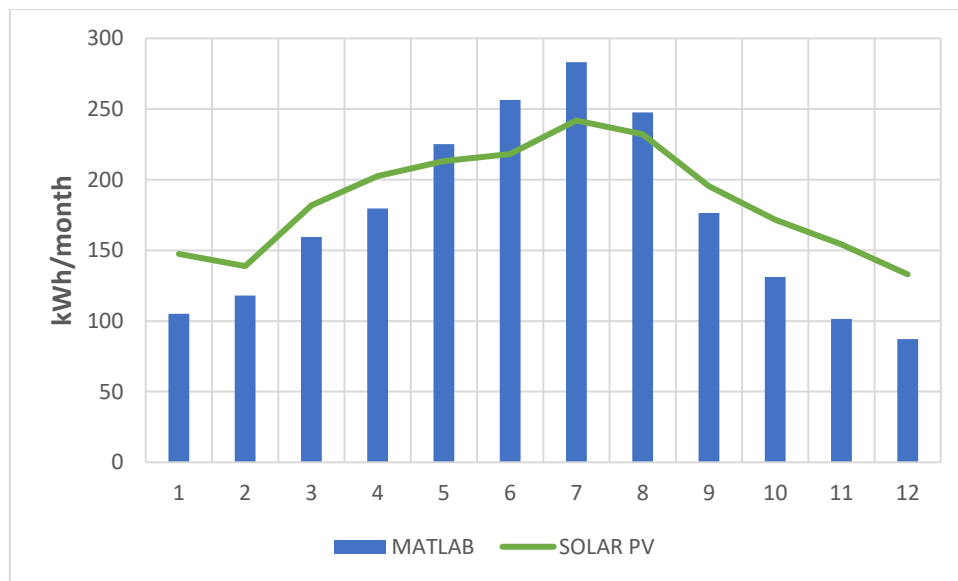


Figure 95: Irradiance onto tilted modules in MATLAB and SOLAR PV

As a result of these assumption, the difference of the two models is emphasized, going from 6.4% higher horizontal irradiance to 7.7% higher irradiance onto the modules. This divergence explains clearly, in turn, the difference of the electricity output throughout the year, which is 7.9% higher in the model developed by SOLAR PV. Figure 26 shows the production forecasts for each month of a year in both models. It can be seen that there is a clear correlation between the difference of irradiance shown in Figure 95 and the difference in the electricity generated by each model shown in Figure 96.

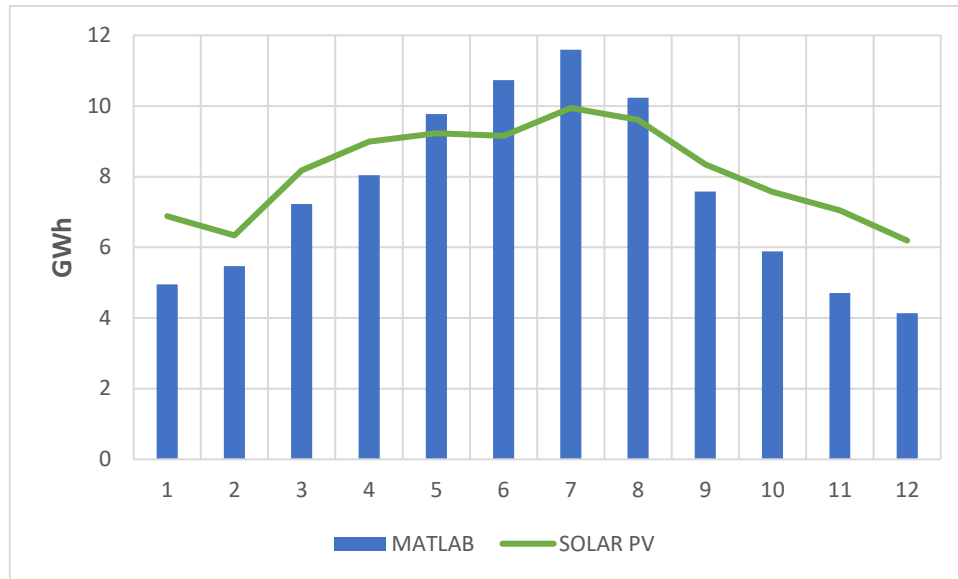


Figure 96: Electricity generation forecasts in MATLAB and SOLAR PV

Finally, the difference between the ambient temperature considered in both models has also an influence on the results. Figure 97 shows the average ambient temperature considered in both models. As it can be seen, the temperatures on which SOLAR PV is based are slightly lower, with an annual average ambient temperature of 14.3°C, compared to 16°C considered in MATLAB. These higher temperatures increase, in turn, the temperature of the modules, decreasing their efficiency and, therefore, the output of the plant.

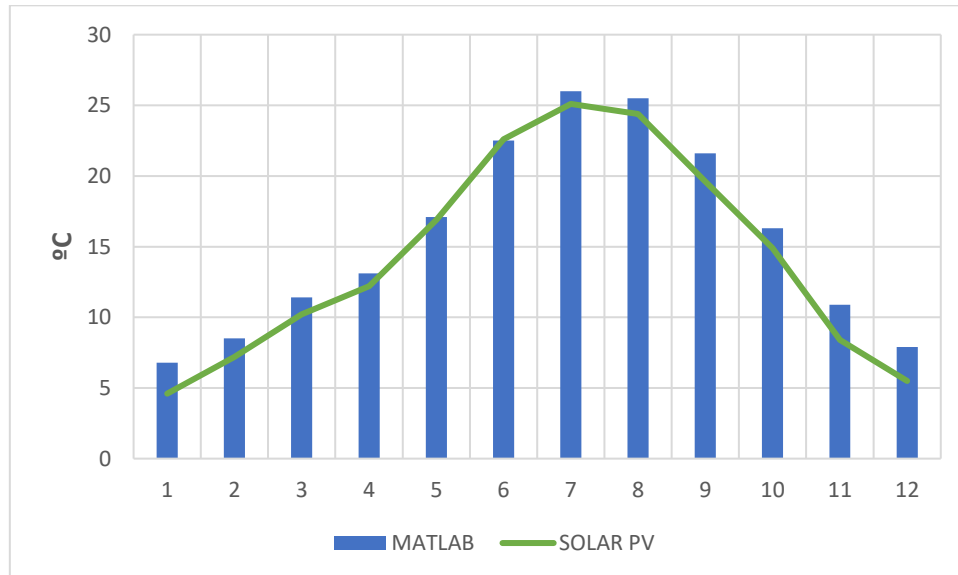


Figure 97: Average ambient temperature in MATLAB and SOLAR PV

In order to determine the influence of the input data in the model developed in MATLAB, a brief sensitivity analysis has been carried out. Firstly, irradiance considered in SOLAR PV has been entered in the model, instead of the data provided by ADRASE. As a result, irradiance onto the modules raises to $2216 \text{ kWh/M}^2 \cdot a$, decreasing the deviation to a value of 0.7% (see Table 12). The electricity generation, for its part, amounts to 95.95 GWh, decreasing the difference between the output of both model to a value of 1.6% (see Table 12).

	MATLAB'	SOLAR PV	Deviation
Horizontal irradiance	1975 $kWh/m^2 \cdot a$	1975 $kWh/m^2 \cdot a$	0 %
Inclination angle	34°	32°	−5.9%
Irradiance onto tilted module	2216 $kWh/m^2 \cdot a$	2231 $kWh/m^2 \cdot a$	0.7%
Electricity generation	95.96 GWh	97.48 GWh	1.6%
Load factor	21.91 %	22.3 %	1.6%

Table 12: Comparison of the main results obtained by MATLAB and SOLAR PV, for the same values of irradiance

Lastly, the ambient temperature considered in SOLAR PV has been introduced in the model developed in MATLAB, so that the influence of this parameter can be verified on the output of the model. Table 13 shows the increase of the production forecasts determined by MATLAB, which amounts to 96.45 GWh . That means that the deviation of the results in SOLAR PV compared to the model is around 1.1%.

	MATLAB''	SOLAR PV	Deviation
Horizontal irradiance	1975 $kWh/m^2 \cdot a$	1975 $kWh/m^2 \cdot a$	0 %
Inclination angle	34°	32°	−5.9%
Irradiance onto tilted module	2216 $kWh/m^2 \cdot a$	2231 $kWh/m^2 \cdot a$	0.7%
Electricity generation	96.45 GWh	97.48 GWh	1.1%
Load factor	22.02 %	22.3 %	1.1%

Table 13: Comparison of the main results obtained by MATLAB and SOLAR PV, for the same values of irradiance and ambient temperature

Taking into account the convergence of the results of both models, it can be considered that the production forecasts for the PV plant are reasonably reliable. However, due to the assumptions carried out in MATLAB, the model developed by SOLAR PV is believed to be more trustworthy. Consequently, the results obtained by this model will be the ones taken into account for the economic analysis, that is, an annual electricity generation of $G_{annual} = 96.45 \text{ } GWh$ and a load factor of $f_{load} = 22.3\%$.

4.2.- Economic feasibility of solar PV generation plant

Figure 98 shows the revenues that the solar PV plant would generate over the period 2020-2050. On the left, the monthly income is included, whereas on the right the annual income is shown. Due to the increase of CCGT generation, together with the increase of the prices of natural gas and CO_2 emission rights, annual income of the PV plant increases between 2020 and 2030, going from 4.71 million € to 8.11 million €. As of 2030, however, the price in the daily market starts to decrease, as a result of the increase in renewable generation. Thus, annual income decreases progressively between 2030 and 2050, reaching a value of 3.68 million € in 2045 and 2.63 million € in 2050.

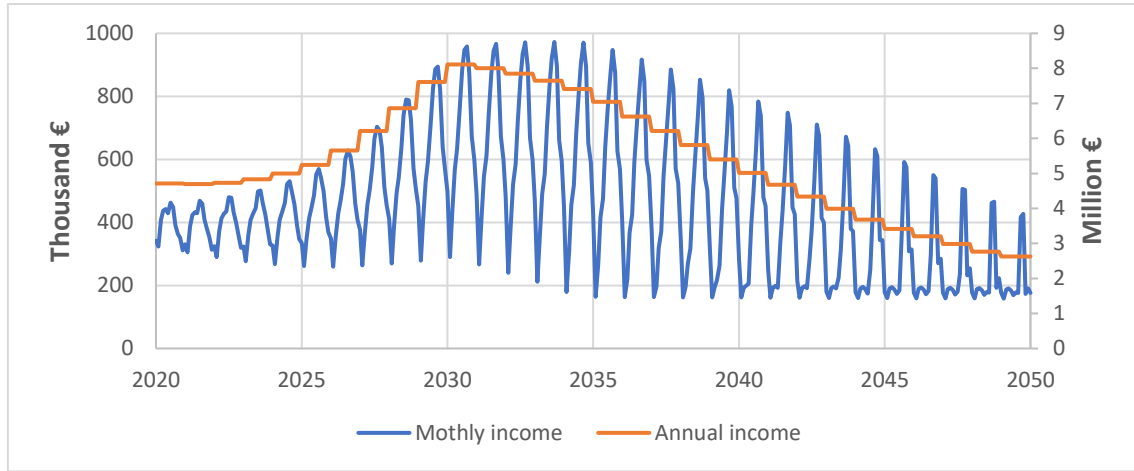


Figure 98: Monthly income (left) and annual income (right) of the PV plant during 2020-2050

Given that, in the beginning, a lifetime of 25 years is considered, the average price perceived during the period 2020-2045 by the solar PV plant amounts to 60.61 €/MWh. In order to verify the economic feasibility of the plant, the Net Present Value NPV and the Internal Rate of Return IRR of the project have been calculated, the main financial indicators by which the feasibility and profitability of a project can be reliably determined.

On the one hand, the NPV represents the present value of the cash flows generated during the lifetime of the project n , taking into account a discount rate r and subtracting the initial investment I :

$$NPV = -I + \sum_{i=1}^n \frac{CF_i}{(1+r)^i} \text{ [€]} \text{ (Eq. 61)}$$

Where,

- I [€]: initial investment.
- CF_i [€]: cash flow in the year i .
- r [%]: discount rate.
- n [years]: lifetime of the project.

In the case of solar PV plant, the initial investment is constituted by the pre-development costs C_{pd} and construction costs C_c , and according to the Equation 62, it amounts to $I = 37,855,000$ €.

$$I = P_{plant} \cdot (C_{pd} + C_c) \text{ [€]} \text{ (Eq. 62)}$$

Where,

- $P_{plant} = 50,000$ kW.
- $C_{pd} = 79.1$ €/kW.
- $C_c = 678$ €/kW.

The cash flows CF_i , on the other hand, represent the profits generated by the plant in the year i , and are the result of the subtraction between incomes and costs of this year, which in the case of solar PV are equal to fixed O&M costs $C_{O\&M_f}$:

$$CF_i = \sum_{j=1}^{12} P_{ij} \cdot G_{el_{ij}} - P_{plant} \cdot C_{O\&M_f} \text{ [€]} \text{ (Eq. 63)}$$

Where,

- P_{ij} [€/MWh]: marginal price of electricity in the daily market corresponding to the year i and the month j .
- $G_{el_{ij}}$ [MWh]: electricity generated by the plant in the year i and the month j .
- P_{plant} [kW]: installed capacity of the plant.
- $C_{O\&M_f}$ [€/kW]: fixed O&M costs.

From the Equations 61, 62 and 63 the expression of the NPV can be obtained for the specific case of the solar PV plant:

$$NPV = -P_{plant} \cdot (C_{pd} + C_c) + \sum_{i=1}^n \frac{\sum_{j=1}^{12} P_{ij} \cdot G_{el_{ij}} - P_{plant} \cdot C_{O\&M_f}}{(1+r)^i} \text{ [€]} \text{ (Eq. 64)}$$

For a lifetime of $n = 25$ years and a discount rate of $r = 10\%$, the Net Present Value of the plant amounts to $NPV = 11,739,127$ €, which implies that the project would be profitable.

The IRR , on the other hand, represents the discount rate with which the project would not generate losses or benefits, that is, with which a Net Present Value of $NPV = 0$ would be obtained. For its calculation, therefore, the Equation 61 will be equal to zero:

$$NPV = -I + \sum_{i=1}^n \frac{CF_i}{(1+IRR)^i} = 0 \text{ [€]} \text{ (Eq. 65)}$$

For a lifetime of $n = 25$ years, the internal rate amounts to $IRR = 13.56\%$, which implies that, due to being higher than the discount rate of $r = 10\%$, the project is indeed economically feasible.

In order to estimate the time in which the initial investment will be recovered, the pay-back PB and the discounted pay-back PB_d have been calculated. Figure 99 shows the operational cash-flow of the solar PV plant during the period 2020-2050. As it can be seen, the initial investment would be recovered in the 8th year of operation. However, if the discounted value of annual cash-flows is taken into account, the initial investment would not be recovered until the 13th year of the project.

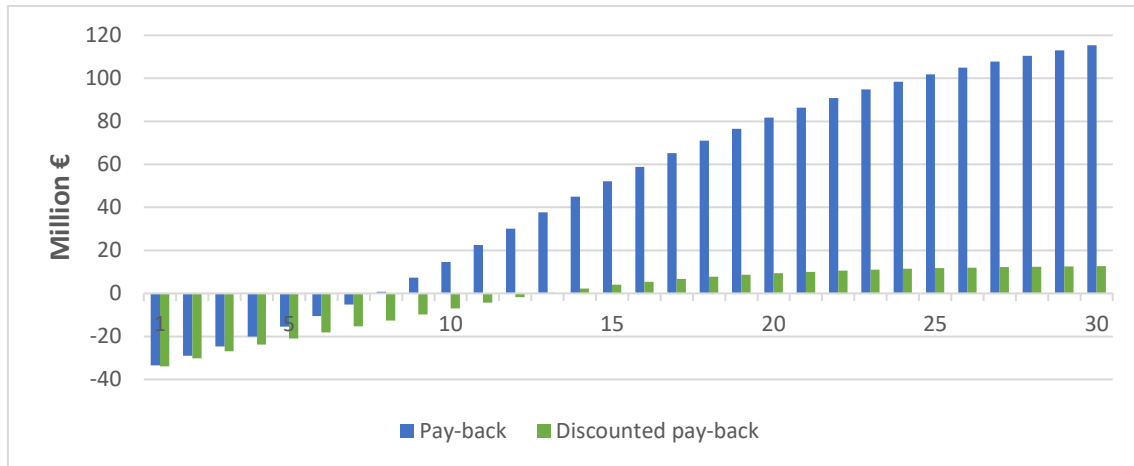


Figure 99: Accumulated Cash-Flow of the solar PV power generation plant with own forecasts, during the period 2020-2045

As a summary, Table 14 includes the Net Present Value NPV and the Internal Rate of Return IRR of the project, as well as the pay-back PB and the discounted pay-back PB_d , for a lifetime of $n = 25$ years and a discount rate of $r = 10\%$.

NPV	IRR	PB	PB_d
11,739,127 €	13.56%	8 years	13 years

Table 14: Financial indicators of the project

Based on these indicators, it can be concluded that the income generated by the sale of electricity in the daily market is enough for the viability of the project. According to these results, therefore, additional financial mechanisms would not be necessary for the profitability of the solar PV power generation plant.

However, due to the uncertainty related to the forecasts of the price of electricity in the daily market, the profitability of the plant could vary based on the price. In order to consider different possible scenarios, the main financial indicators have been calculated for different prices in the daily market. In this analysis, average values have been considered, so that the price of the electricity will be, in each case, constant throughout the lifetime of the project.

For a lifetime of $n = 25$ years and a discount rate of $r = 10\%$, the minimum average price at which electricity should be sold in order to make the project feasible is around 45.91 €/MWh. As it can be seen the Table 15, with prices below this limit the initial investment is not recovered, with IRR s below 10%. Conversely, if higher electricity prices are considered, the project result profitable.

Electricity price	NPV	IRR	PB	PB _d
30 €/MWh	−14,078,647 €	4.76%	15 years	-
35 €/MWh	−9,654,355 €	6.52%	13 years	-
40 €/MWh	−5,230,062 €	8.16%	11 years	-
45 €/MWh	−805,769 €	9.73%	10 years	-
50 €/MWh	3,618,524 €	11.23%	9 years	19 years
55 €/MWh	8,042,817 €	12.69%	8 years	15 years
60 €/MWh	12,467,110 €	14.11%	7 years	13 years
65 €/MWh	16,891,403 €	15.05%	7 years	11 years
70 €/MWh	21,315,696 €	16.88%	6 years	10 years
75 €/MWh	25,739,989 €	18.23%	6 years	9 years
80 €/MWh	30,164,282 €	19.57%	6 years	8 years

Table 15: Main financial indicators for different electricity price in the daily market

4.3.- Economic feasibility of CCGT power generation plant

4.3.1.- Analysis of the price in the adjustment services market

As it has been mentioned in the Section 3.2, CCGT power generation plants have the function of covering the peaks of demands, as well as giving the necessary support in a generator mix with a considerable penetration of non-manageable sources. For this reason, a large part of the electricity generated by CCGTs is not offered in the daily market, but in the adjustment services market. Therefore, when analysing the economic viability of these plants, the price of the electricity in this market will be considered.

As explained in the Section 2.1, the adjustment services market is intended to maintain the electrical system in physical equilibrium and within an adequate safety margin. These services work by market mechanisms, and the most important are the solution of technical restrictions, secondary and tertiary regulations, management of deviations and restrictions in real time.

These services are remunerated both for generating additional energy and for reducing the generation expected for each period of the daily program. Figure 100 shows the energy to be raised negotiated in the different adjustment markets in the recent years, as well as the average price received in each year. As it can be seen, the largest volume of energy to be raised is traded in the market for technical restrictions, with an average percentage of 58% over the total volume traded in the last 8 years. The average price received in the market, for its part, suffers significant variations from one year to the next, recording an average price of 88 €/MWh in the same period.

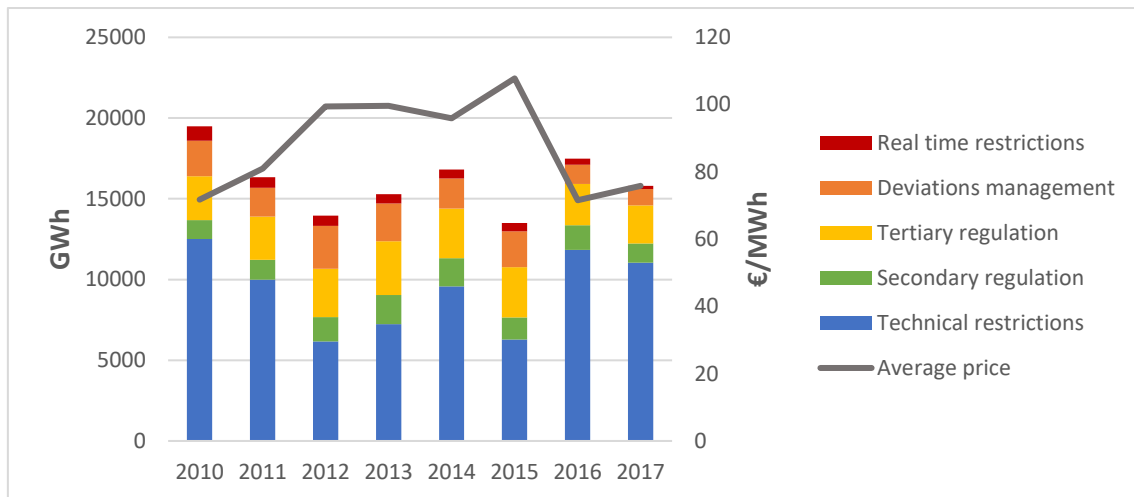


Figure 1100: Energy to rise annually traded in the adjustment markets (left) and its annual average price in the adjustment markets (right) (Co-adapted from [20])

Figure 101, on the other hand, shows the energy to be reduced negotiated in the different adjustment markets during the last 8 years, as well as the average price received in each of them. In this case, tertiary regulation has the highest sales volume with 37% of the total, followed by the secondary regulation with 22%. Compared to the energy to be raised, whose total volume negotiated each year amounts to an average of 16,084 GWh/year, the energy to be reduced has more modest figures, with an average volume of 6000 GWh/year in the last 8 years.

The price of the latter, likewise, is considerably lower than that corresponding to the energy to be raised, with an average value of 27 €/MWh in the last 8 years. Overall, the market of technical restrictions is the most important, with 44% of the total volume traded in the same period.

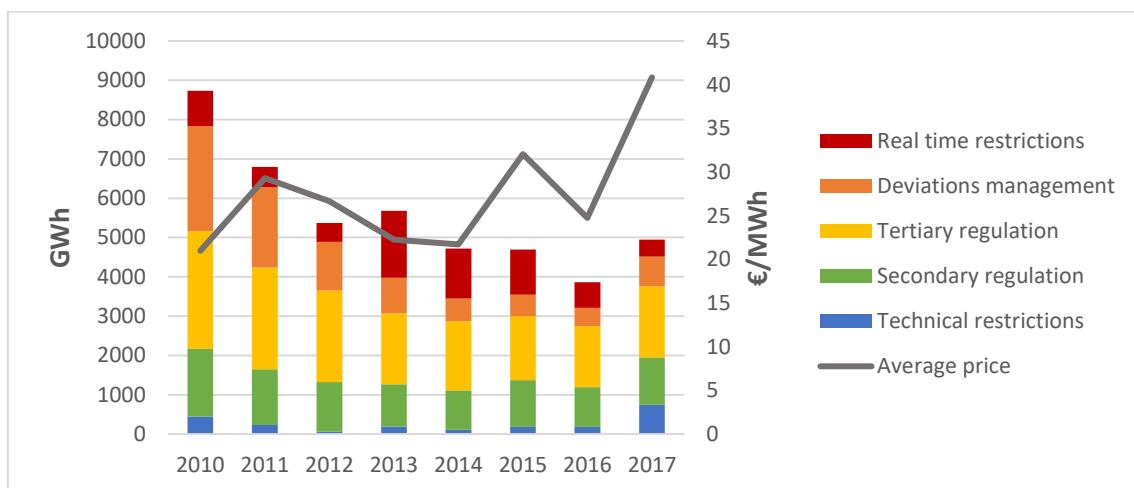


Figure 101: Energy to decrease annually traded in the adjustment markets (left) and its annual average price in the adjustment markets (right) (Co-adapted from [20])

In relation to the price received in the adjustment services markets, there is a great difference between the sales prices of each market. However, the average price calculated from the amount of energy traded and its price in the different markets, shows a similar evolution to that

recorded in the daily market. Figure 102 shows the evolution of the average monthly prices perceived in both markets in the last 8 years and it can be seen how both curves follow a similar evolution.

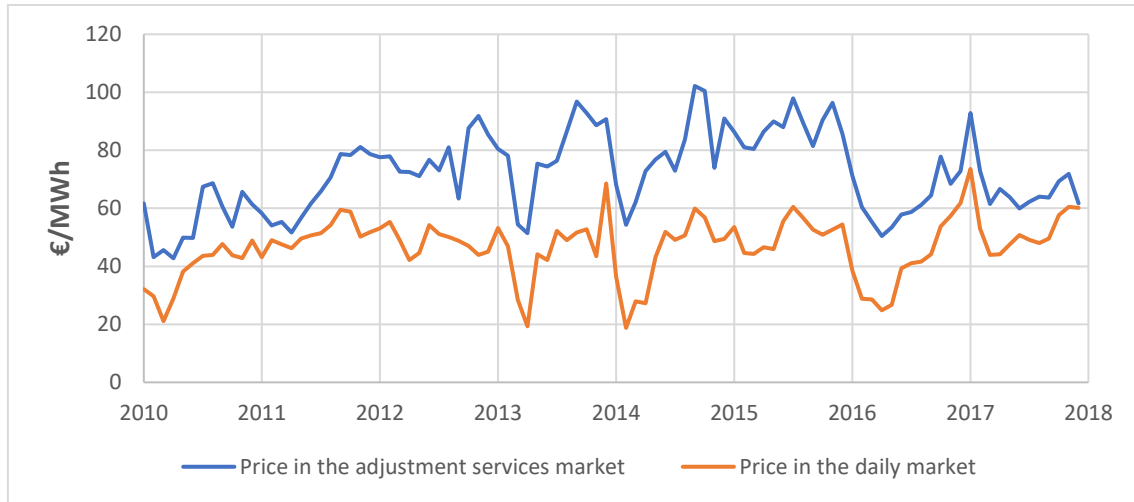


Figure 102: Electricity Price in the daily market and the adjustment services market (Co-adapted from [20])

Given this correlation, there is a possibility of basing the forecasts of the price in the adjustment markets on the ones made for the price in the daily market. In order to ensure that this relationship exists and, therefore, in order to validate these forecasts, the Pearson correlation coefficient for both prices has been calculated, based on the monthly data of the last 8 years. Both prices show a positive correlation of $r = 0.62$, that is, there is a moderate correlation between them (see Figure 103). As a result, it will be assumed that the average price received in the adjustment markets will evolve proportionally to the expected price in the daily market.

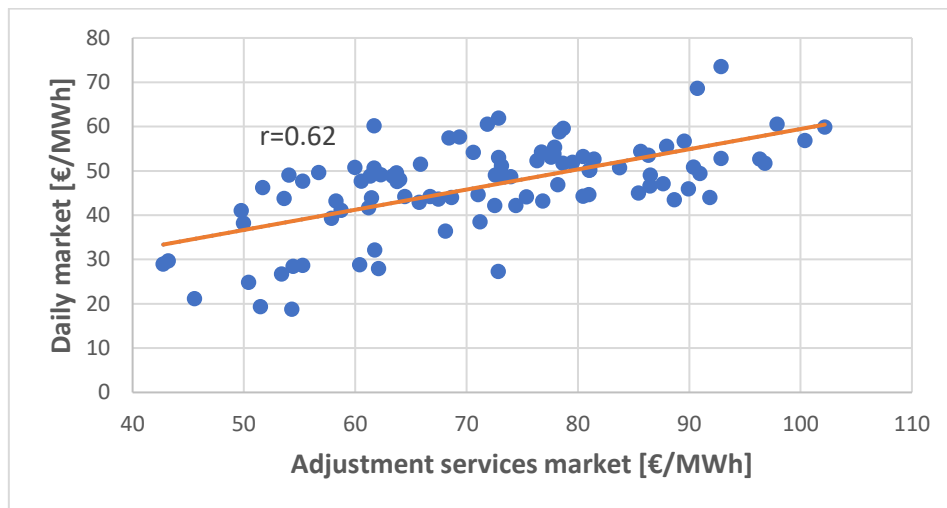


Figure 103: Correlation between the price in the adjustment services market and the price in the daily market

According to this assumption, thus, the price of electricity in the adjustment services market would take the values shown in Figure 104. As in the forecasts for the daily market, the price in the adjustment market would undergo an important raise in the short term, reaching in 2030 a

maximum of 152 €/MWh. In the long term, however, the price would reduce below the current values, reaching in 2050 a value of 30 €/MWh. Finally, as in the daily market, the seasonality of the price is expected to increase, given the progressive penetration of renewable energies, on the one hand, and the increase in the prices of natural gas and the CO₂ emission rights.

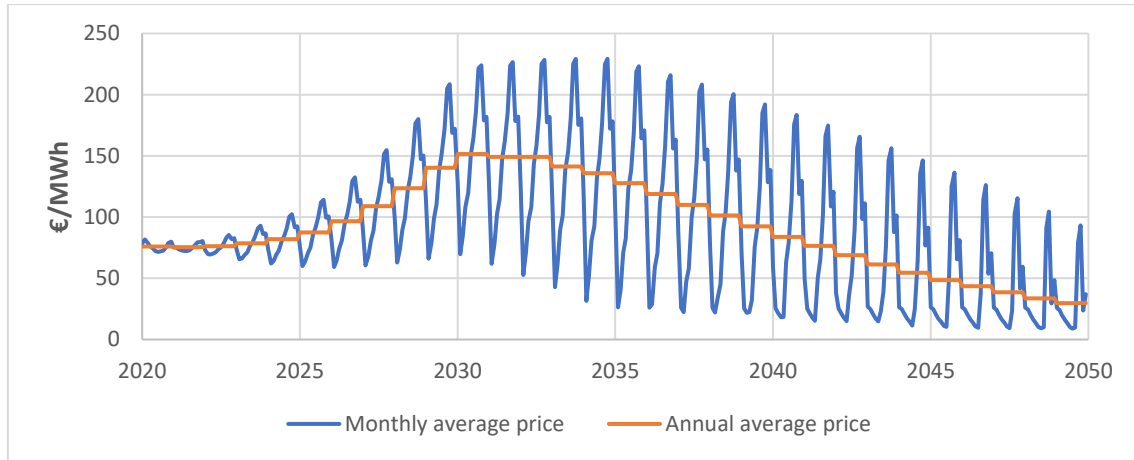


Figure 104: Forecasts for the electricity price in the adjustment services market for the period 2020-2050

Finally, despite its irrelevance for this analysis, the evolution of the amount of energy traded in the adjustment market has been estimated for the period 2020-2050. Given that the adjustment services have a special relevance when there is a high share of non-manageable power generation sources, a comparison has been made between the energy traded in the adjustment market and the renewable generation during the last 8 years (see Figure 105).

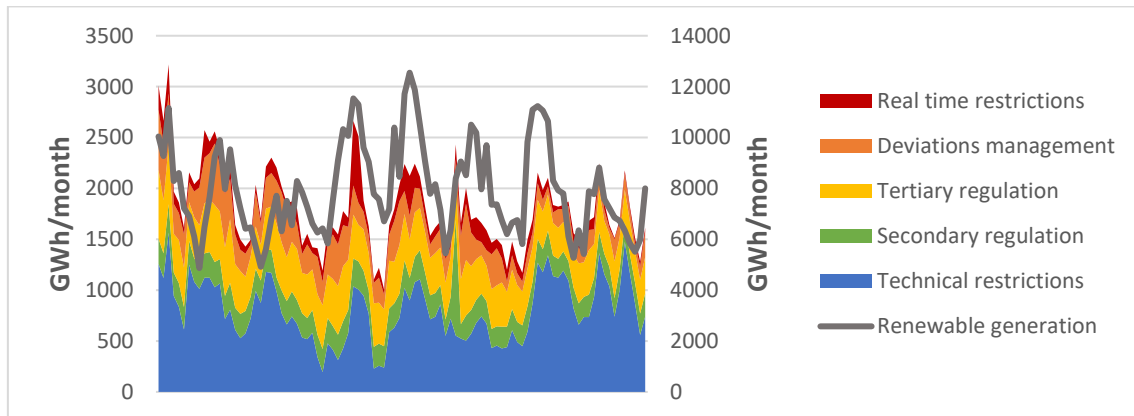


Figure 105: Electricity traded in the adjustment markets in each month (right) and renewable generation in each month (right) during the period 2010-2017 (Co-adapted from [20])

Figure 106, on the other hand, shows the linear correlation between both variables, which have a Pearson correlation coefficient of $r = 0.46$.

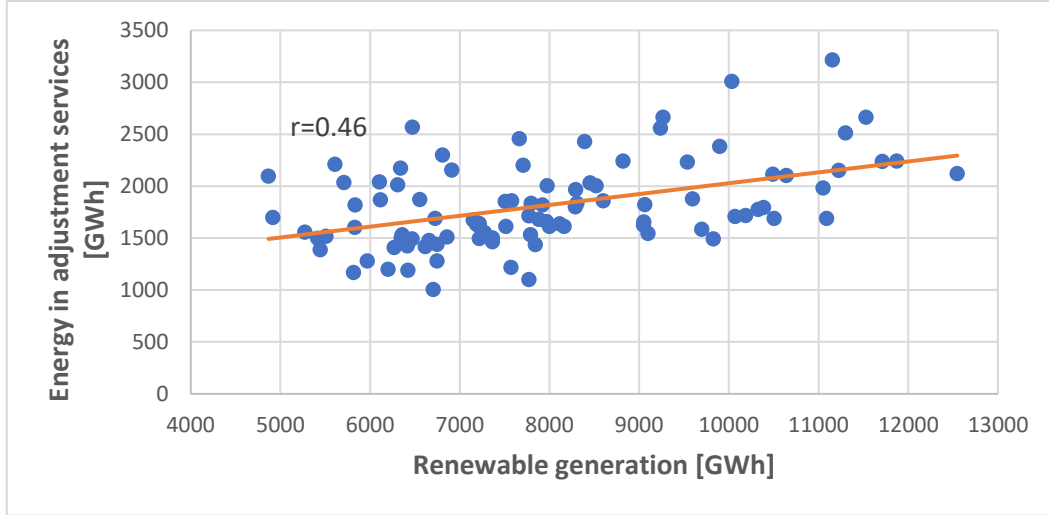


Figure 106: Correlation between energy traded in adjustment services and renewable generation during the period 2010-2017

This correlation reveals that the relationship between both variables is not so high and that, consequently, the forecasts made based on them would be quite unreliable. Nevertheless, the energy traded in the adjustment market during the period 2020-2050 could be roughly estimated based on this relation, that is, based on the forecasts of renewable generation for the same period.

4.3.2.- Financial parameters of the plant

Based on the forecasts carried out in the Section 3.1, it is expected that the contribution of the CCGTs to the generator mix will increase slightly in the short term, reaching in 2025 an annual average load factor of 27.9%. Due to the progressive penetration of renewable energies, however, in the long term the role of CCGTs in the generator mix is expected to reduce dramatically, reaching in 2050 a load factor of 1.3%. Overall, a CCGT plant commissioning in 2020 would have an average load factor of 18.64% during its lifetime, that is, between 2020 and 2045.

For the feasibility analysis, a CCGT power generation plant of $P_{CCGT} = 50 \text{ MW}$ has been considered, whose useful life would be, as indicated in Table 3, of $n = 25 \text{ years}$, and which would require an initial investment of $I = 28,815,000 \text{ €}$. The electricity generation forecasts G_{CCGTij} , likewise, is based on the average load factor foreseen for this technology and has been calculated with the Equation 66.

$$G_{CCGTij} = P_{CCGT} \cdot f_{lij} [\text{GWh/month}] \text{ (Eq. 66)}$$

Where,

- P_{CCGT} : capacity of the CCGT power generation plant.
- f_{lij} : average load factor of CCGT technology in month j and year i .
- G_{CCGTij} : electricity generated by the plant in month j and year i .

Figure 107 shows the evolution of the expected electricity generation during the operational life of the plant. It shows how electricity generated increases slightly between 2020 and 2025, whereas in the long term there is a considerable decrease.

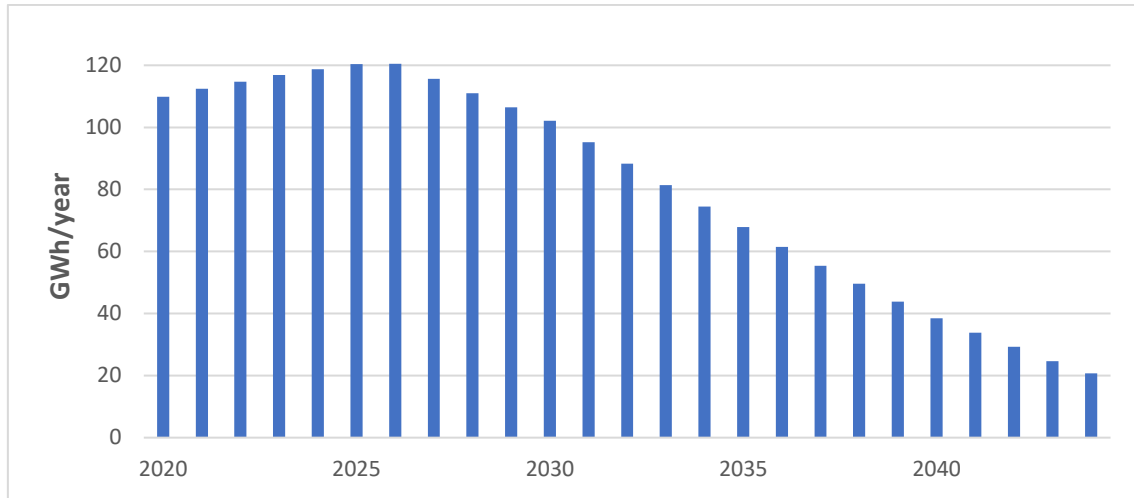


Figure 107: Forecasts of the electricity generated by the CCGT power generation plant during 2020-2045

Although the average price of electricity negotiated in the adjustment market during the period 2020-2045 would amount to 102.7 €/MWh, the price received by the CCGT plants would be 124.6 €/MWh. This is due to the fact that in the months where renewable generation is higher and, consequently, the price of electricity in the market is lower, CCGT plants generate little electricity. On the contrary, in the months where renewable sources are scarce CCGTs sell the greatest amount of energy. During this months, thus, this technology is more frequently the marginal technology and, therefore, the average price of the electricity is higher.

Based on the forecasts of generation, on the one hand, and the price of electricity in the adjustment markets, on the other, the revenues that the plant would have during its operational life have been calculated. Figure 108 shows the monthly income over the period 2020-2045, as well as the income that the plant would generate each year during the same period. As it can be seen, the monthly income follows a seasonality that depends on the generation of the plant each month and the difference in prices from one month to the next. Likewise, it can be seen how annual revenues would increase in the short term, going from 8.27 million €/year in 2020 to 17.3 million €/year in 2030. In the long term, conversely, incomes would be progressively reduced, reaching in 2045 a value of 2.33 million €/year.

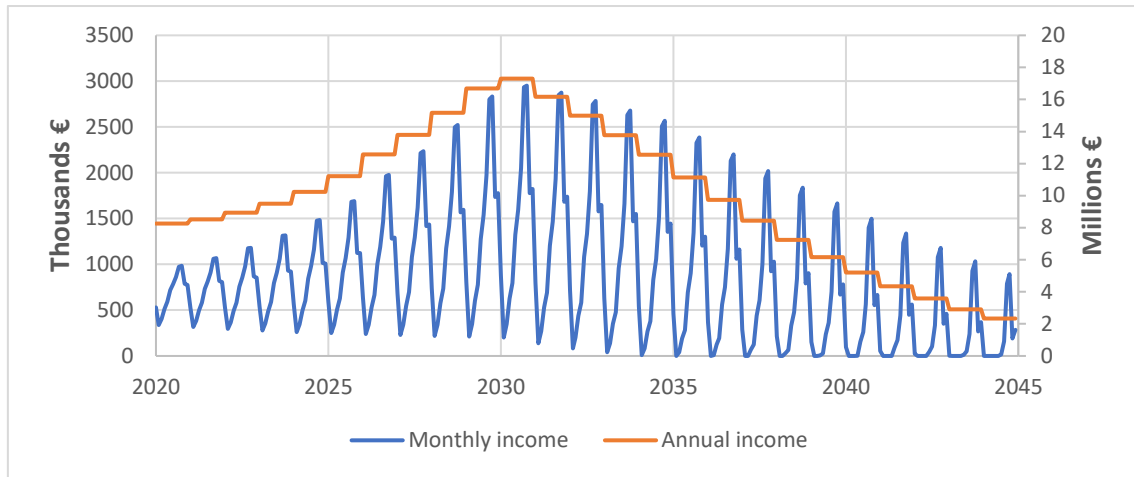


Figure 108: Monthly income (left) and annual income (right) of the CCGT plant during the period 2020-2045

Based on these forecasts, for a lifetime of $n = 25$ years and a discount rate of $r = 10\%$, the plant would be economically viable, with a Net Present Value of $NPV = 13,602,559$ € and an Internal Rate of Return of $IRR = 15.15\%$. The Pay-Back would be around $PB = 8$ years, whereas the discounted Pay-Back would be $PB_d = 11$ years. Figure 109 shows the accumulated cash-flow of the project and the accumulated cash flow considering the discount of 10%.

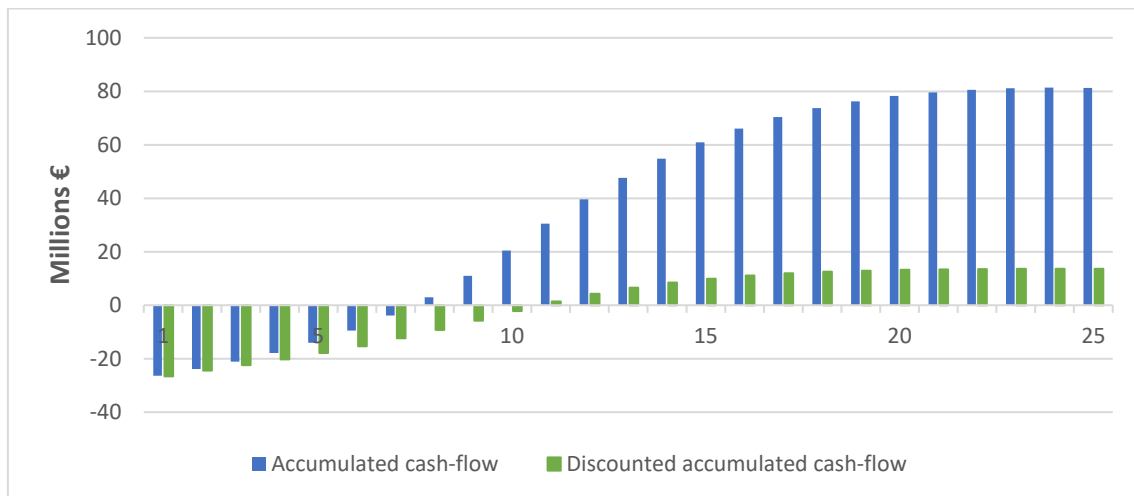


Figure 129: Accumulated cash-flow of the CCGT power generation plant during its lifetime

Finally, it should be noted that the analysis carried out has been based on the assumption that all the energy generated by the plant would be sold in the adjustment market. However, part of the electricity generated by CCGTs is sold in the daily market and given that the price in this market is lower than the one received in the adjustment market, the future revenues for the plant could be lower.

In order to consider this factor, different scenarios have been calculated based on the percentage of energy sold in the daily market, from 0% to 50%. Table 16 shows the main financial parameters for each scenario. As it can be seen, from a percentage of sales of 40% in the daily market, the plant would no longer be economically feasible. As a result, additional

financing mechanisms would be necessary to counteract the deficit of these plants. Table 16 includes the average capacity payments CP that would be necessary throughout the lifetime of the plant to achieve the minimum Internal Rate of Return, that is, $IRR = 10\%$. Therefore, these payments represent the values from which the plant would be economically profitable.

Sales in the daily market	Received price [€/MWh]	NPV [€]	IRR [%]	PB [year]	PB_d [year]	CP [€/MW/year]
0%	124.6	13,602,559	15.15	8	11	0
10%	119.2	9,516,886	13.71	9	12	0
20%	113.8	5,437,663	12.19	9	14	0
30%	108.4	1,364,970	10.57	10	17	0
40%	103	-2,696,173	8.83	10	—	5,950
50%	97.6	-6,743,772	6.91	11	—	14,900

Table 46: Financial parameters for different scenarios of the CCGT power generation plant

5.- ECONOMIC ANALYSIS BASED ON DIFFERENT FORECASTS

5.1.- Different price of the electricity in the daily market

The economic analysis of solar PV and CCGT power generation plants has been based on own forecasts carried out for the price of the electricity during the period 2020-2050. Due to the uncertainty inherent to this type of forecasts, however, the results could diverge considerably from the real price received during this period. That is the reason why it has been considered convenient to make a comparison between the forecasts already carried out and the ones made by an entity specialized in the sector. Likewise, the main financial parameters for both solar PV and CCGT plants have been calculated, so that both scenarios are taken into account.

The estimates of the price of electricity for the period 2020-2050 have been determined based on the study carried out in March 2016 by Deloitte on the future energy model in Spain [25]. According to this, the closure of the current coal-fired power plants would mean a new investment in CCGT, which would produce an increase in price of the daily market that would represent an additional cost of between 25,000 *million* € and 35,000 *million* € in the period 2020-2030 [25].

In the present project, an average value of 30,000 *million* € will be considered, which would mean, considering the evolution of electricity demand, an average rise of 8.76 €/MWh in the period 2020-2030. Given that the reason for this rise would be the increase in the generation by CCGTs, it will be assumed that the price will evolve proportionally to the increase of CCGTs' generation.

In the long term, however, a general drop in the price is expected, reaching in 2050 values equal to the 40% of the price recorded in 2015, which would mean a price in the daily market of 28.7 €/MWh. Given that this downward trend is owing to the progressive increase of renewables in the electricity mix and taking into account that a virtually linear evolution of renewable generation has been assumed, a linear reduction will be assumed for the price in the daily market during the period 2030-2050.

Figure 110 shows the forecasts of the price of electricity in the wholesale market for the period 2020-2050 based on these new estimates. It also includes the own forecasts, so that a comparison between both forecasts can be made. As it can be seen, the increase in the price foreseen by own forecasts in the medium term differs considerably from that considered by Deloitte. While the former would reach a peak value of 82.9 €/MWh in 2030, the latter would raise only to 62.1 €/MWh, that is, 25% less than expected. In the long term, however, both forecasts converge to very close values, reaching in 2050 values of 27.4 €/MWh and 28.7 €/MWh, respectively.

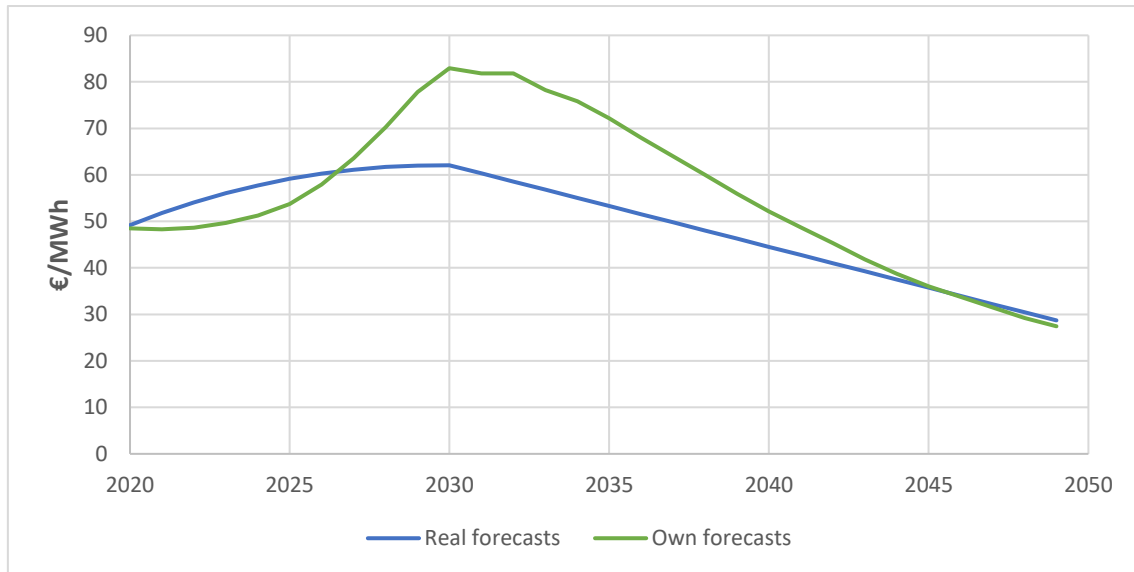


Figure 1310: Comparison of the different forecasts for the electricity price in the daily market for the period 2020-2050

5.1.1.- Economic analysis of solar PV

Based on the new forecasts, the average price received by the solar PV power generation plant during the period 2020-2045 would be 52.78 €/MWh, compared to 60.61 €/MWh calculated previously. Figure 111 shows the evolution of the expected revenues of the plant during the period 2020-2045, which responds to the evolution of the average prices foreseen in the daily market for the same period.

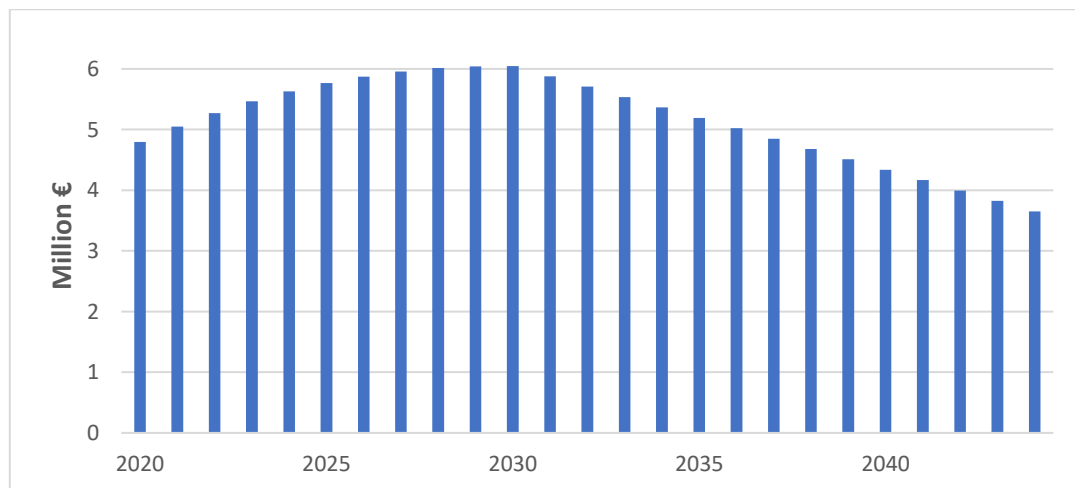


Figure 111: Forecasts of the annual income of the solar PV power generation plant for the period 2020-2045

Considering a discount rate of $r = 10\%$, the Net Present Value of the project would be $NPV = 8,117,283$ €, which implies that the project would continue to be profitable in this new scenario. However, its Internal Rate of Return would take a value of $IRR = 12.95\%$, slightly slower than in the previous scenario ($IRR = 13.55\%$). Finally, Figure 112 shows the evolution of the cumulative cash flow of the project throughout the life of the plant. It shows how the Pay-Back

would be $PB = 8$ years, whereas the discounted Pay-Back would take a value of $PB_d = 14$ years.

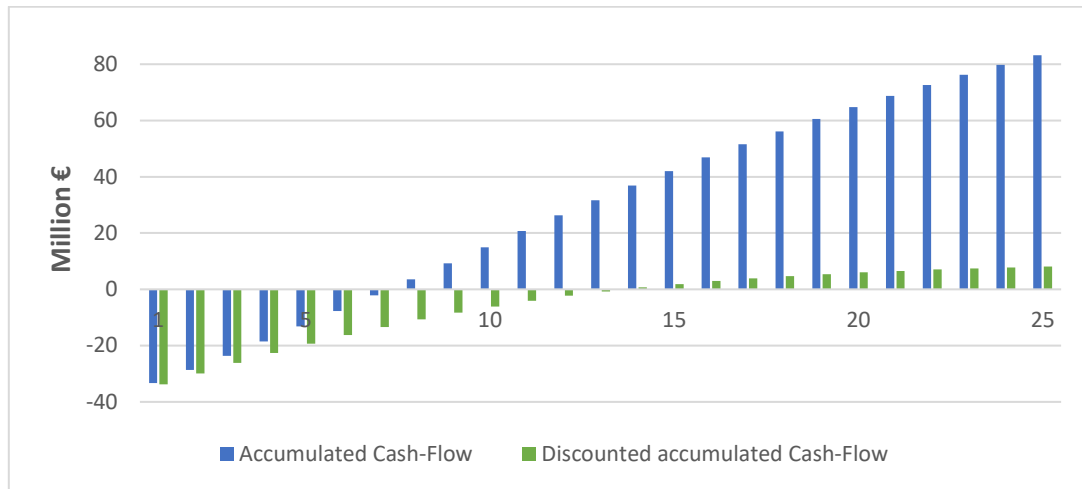


Figure 112: Accumulated Cash-Flow of the solar PV power generation plant during the period 2020-2045

5.1.2.- Economic analysis of CCGT

For the forecasts of the price of electricity in the adjustment markets, the same correlation with the daily market carried out in the Section 4.3 has been considered. Assuming therefore a linear relationship between the prices in both markets, the price in the adjustment markets would follow the evolution shown in Figure 113. It also includes the price calculated in the previous analysis, so that both results can be compared.

According to the new forecasts, the average price in the adjustment markets would reach a maximum of 105.7 €/MWh, far from the 151.5 €/MWh calculated by the own model. This deviation suggests, therefore, that the estimated income for the CCGT plant in the previous analysis could be higher than those actually received during the period 2020-2045 and that, consequently, the financial parameters calculated from these revenues are not entirely reliable.

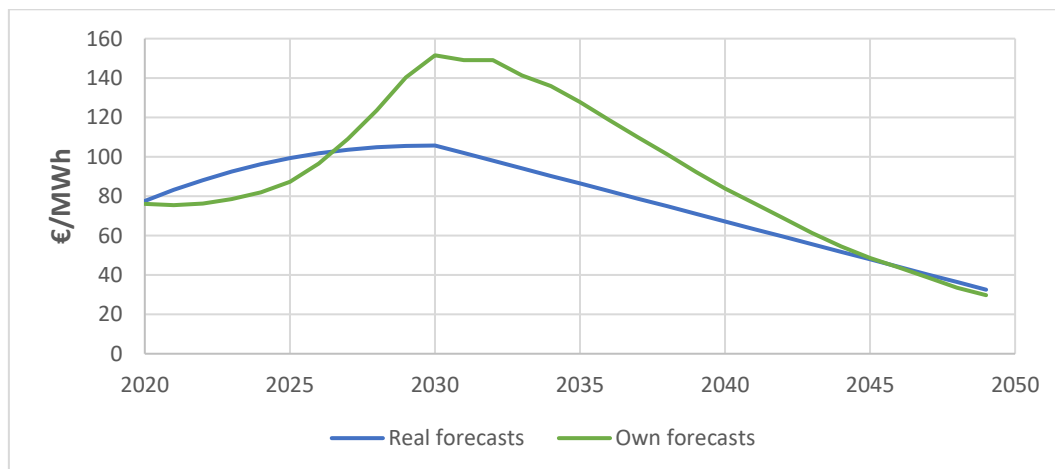


Figure 113: Comparison of the different forecasts for the electricity price in the adjustment services market for the period 2020-2050

Figure 114, for its part, shows the expected income of the CCGT plant throughout its operational life, assuming that all the electricity generated would be sold in the adjustment markets. The figure includes also the variable costs that would have the plant each year due to the electricity generated. As it can be seen, as of 2037, the variable costs would be higher than the income. This fact does not make sense, provided that the price of the offers carried out by the plant in the market would be based on its variable costs, as explained in the Section 3.2 and, more thoroughly, in the Appendix 8.2. This contradiction will be discussed later in this section.

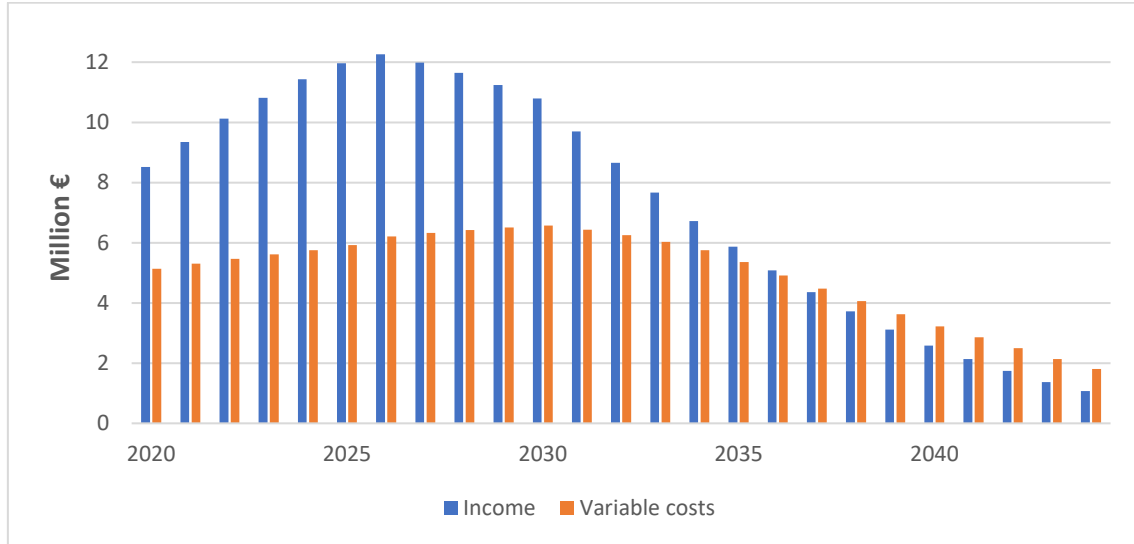


Figure 114: Forecasts for annual income and variable costs of the CCGT power generation plant during the period 2020-2045

As a result of the rise of the price between 2020 and 2030, as well as the increase in the load factor of the plant during this period, income would increase considerably, going from 8.5 million € in 2020 to 11.8 million € in 2030. As of this year, however, income would reduce progressively, due to the reduction in the price of electricity, on the one hand, and the reduction in the plant's load factor.

Overall, the average price received by the plant would be 91.4 €/MWh, 26.6% lower than in the previous analysis, which amounted to 124.6 €/MWh. Considering as well a discount rate of $r = 10\%$, the Net Present Value of the project would take a negative value of $NPV = -863,470$ €, which implies that the project would not be profitable. The Internal Rate of Return would be $IRR = 9.38\%$, below the minimum 10% required for the viability of the project.

In this context, capacity payments CP would be required to ensure the return of the capital and an additional profitability. For the present case, that is, a plant commissioning in 2020 and with a lifetime of 25 years, the annual payment that would ensure a minimum rate of $IRR = 10\%$ would amount to $CP = 1900$ €/MW/year.

Finally, due to the fact that not all the electricity generated by the plant would be sold in the adjustment markets, alternative scenarios have been studied based on the percentage of energy sold in the daily market. Since in this one the price is generally lower than the one received in the adjustment markets, the project would be even less profitable in these scenarios. Table 17 shows the main financial parameters for each scenario.

Sales in the daily market	Received price [€/MWh]	NPV [€]	IRR [%]	PB [year]	PB _d [year]	CP [€/MW/year]
0%	91.4	-863,470	9.38	7	—	1900
10%	87.8	-4,057,190	6.86	8	—	8950
20%	84.2	-7,217,995	3.74	8	—	15,900
30%	80.6	-10,342,626	—	—	—	22,800
40%	77	-13,435,599	—	—	—	29,600
50%	73.4	-16,484,578	—	—	—	36,300

Table 57: Financial parameters for different scenarios of the CCGT power generation plant

As it can be seen, with the alternative forecasts of the price of the electricity, the CCGT plant would not be profitable in any of the scenarios. With regard to the capacity payments necessary to ensure their profitability, they turn out to be very similar to those issued by the Spanish government in the last decade. Between 2007 and 2012 these were 20,000 €/MW/year. In 2012, capacity payments raised to 23,400 €/MW/year and in 2013 to 26,000 €/MW/year. As of this year, however, payments have been reduced to 10,000 €/MW/year, which implies that the CCGT plant would be economically feasible only for a percentage of daily market sales of 0% and 10% [26].

The economic analysis for both solar PV and CCGT power plants have been based on the average price if electricity received in the wholesale market. For marginal technologies such as CCGTs, however, this price might not be representative when estimating the expected income. As it can be seen in Figure 115, from 2037 the average price in this second analysis would be lower than the variable costs of generating the electricity. This fact implies that a lower price than the one actually received is being considered and that, therefore, the average price of the electricity cannot be representative for the case of CCGTs.

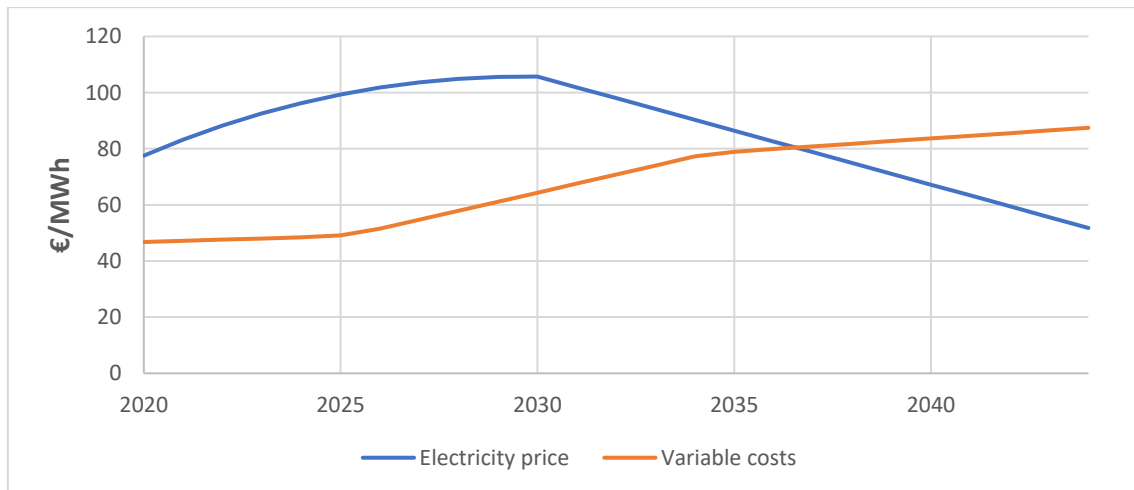


Figure 115: Forecasts for the electricity price in the adjustment services market and the variable costs of the CCGT power generation plant

By means of the model developed in the Section 3.2 for the forecast of the price of the electricity, the monthly evolution of the price has been calculated during the period 2020-2050. This monthly analysis allowed to detect more accurately the difference between the average

price in the market and the price received by the plant. As it can be seen in Figure 116, in this case the variable costs of the plant are lower than the sale price of electricity, which is more in line with reality. Nevertheless, it should be noted that the upward and downward trends of both variables foreseen by the model are contradicting. Thus, it is concluded that the price foreseen by the model is not representative either.

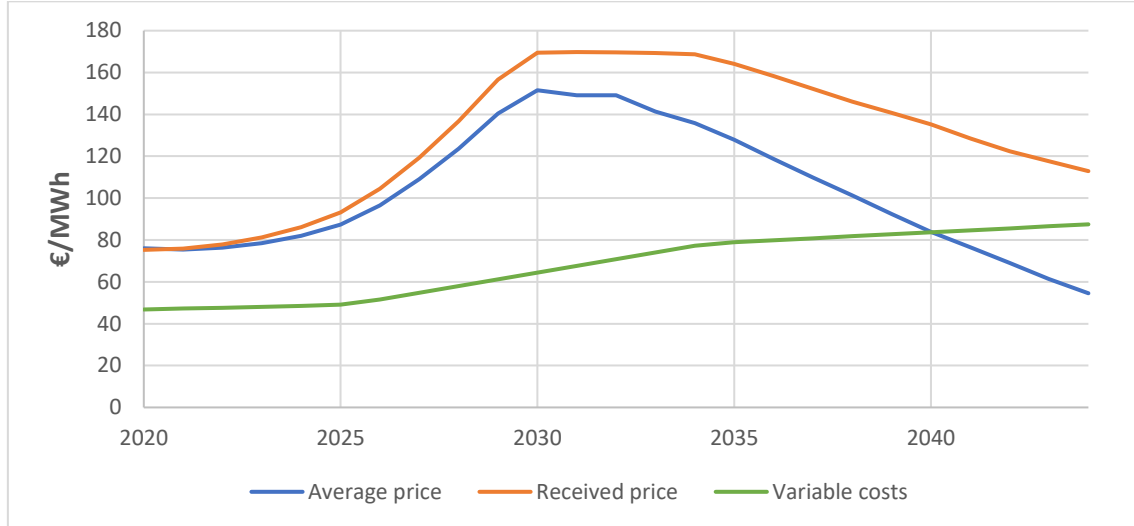


Figure 116: Own forecasts for the average price and received price by the CCGT power generation plant in the adjustment services market, as well as its variable costs during 2020-2045

In order to make a reliable economic analysis of a marginal technology such as CCGTs, a daily evolution of the electricity price should be needed. However, in order to have an idea of the price that the plant would need in order to be profitable, the following calculation has been carried out.

Given that the electricity generated by marginal technologies is sold at the price fixed by them, it is assumed that all the energy generated by the CCGT plant is sold at the price fixed by itself. Assuming that the price of the offers is based on the variable costs of the plant, it is concluded that, in order to reach a minimum rate of $IRR = 10\%$, the price of the electricity should be 76.27% higher than the variable costs of the electricity generated throughout the years. That means that the average price received by the CCGT plant during its lifetime should amount to 119.8 €/MWh.

5.2.- Different load factor for CCGTs

Finally, it should be noted that this required price can change depending on the amount of energy generated by the CCGT plant during its operational life. In the analyses carried out until now, the load factor calculated in the Section 3.1 has been considered, which could turn out to be different, due to the uncertainty inherent to the forecasts. Therefore, the average minimum price at which the electricity should be sold in order to be a profitable project has been calculated for different average load factors and a discount rate of $r = 10\%$.

For the sake of simplicity, it has been assumed that the electricity output would be constant during the lifetime of the plant. Likewise, assuming, as in the previous analysis, that the sale

price is based on the variable costs of the electricity, the percentage of the price has been calculated in relation to the variable costs. These results are shown in Table 18, which includes several scenarios between a load factor of 5% and 50%. It can be seen that the price needed in the market changes dramatically depending on the load factor. Therefore, it is concluded that the analysis of the economic feasibility of a CCGT plant should be based on the forecasts of the load factor of the plant during its operational life. Depending on this variable, the minimum price at which electricity should be sold could be calculated for a certain discount rate. The feasibility of the plant would depend, ultimately, on the competitiveness of this price in the electricity market.

Load factor [%]	Percentage in relation to variable costs [%]	Required average price for feasibility [€/MWh]
5%	306.9%	276.5
10%	156.4%	174.2
15%	106.2%	140.1
20%	81.1%	123
25%	66%	112.8
30%	56%	106
35%	48.8%	101.1
40%	43.5%	97.5
45%	39.3%	94.6
50%	35.9%	92.3

Table 18: Required minimum price of electricity in order to make the CCGT plant profitable, considering different load factors

6.- CONCLUSIONS

The analysis of the energy sector carried out in Section 2.2 concludes, on the one hand, that the increase in the demand of primary energy will come from developing countries, whereas the demand in the OECD countries is expected to remain constant in the mid-term and decrease slightly in the long term. On the other, a global energy transition towards a low carbon economy is expected, in which countries such as China and India will acquire an increasingly relevant role, together with the European Union.

Regarding the expectations of generation technologies, solar PV will constitute, due to the reduction of its learning curve, the most implemented renewable source throughout the period 2020-2040. Likewise, thanks to its low CO_2 emissions compared to other thermal technologies and due to the need of a flexible backup capacity as a result of the massive entrance of renewables in the coming years, CCGT is expected to acquire greater relevance in the mid-term generation mix.

From the forecasts of the future Spanish electricity mix carried out in Section 3.1, it is concluded that the share of renewable energies will increase progressively in the coming decades, reaching in 2050 an approximate value of 90%. These forecasts have been based on the assumption that the objectives established by the European Union in terms of environmental policies will be met. Given the current economic recovery of the country and the slightly favourable forecasts regarding the tariff deficit (see Appendix 8.1), it is believed that Spain will be able to commit itself to future environmental measures and that, therefore, the forecasts made in this project are rather reliable.

Due to the environmental measures that are being taken today at a European level, on the other hand, a progressive closure of coal and fuel oil thermal plants is expected during 2020 and 2030. This disappearance of an important part of the thermal park will cause an increase in the generation of CCGTs in the mid-term. In the long-term, however, its load factor will be considerably reduced, reaching in 2050 values well below the current ones.

Finally, given the uncertainties of the expected energy transition, the life of the currently operating nuclear power plants is expected to last 20 years more, being operative, therefore, until the middle or the end of the 2040s. In this project it has been considered that the nuclear park will be operational until 2050. However, due to technological or legislative factors, nuclear power plants could close earlier than expected, causing significant changes in the foreseen generator park. An accelerated development of storage technologies could also displace CCGTs as a backup technology.

The analysis of the price of electricity in the daily market conducted in Section 3.2 concludes that the determining factors of the price of electricity are the generation structure and the prices of the energy products, which influences the variable costs of the different technologies and, therefore, the sale price offered by them. It has also been concluded that, given that some technologies are marginal more frequently, not all technologies have the same degree of influence when setting the price in the market.

From the analysis of the different energy products carried out in Section 3.2.3, it has been concluded that the price of CO_2 emission rights will increase considerably in the long term. For

natural gas, on the other hand, an increase is expected in the short and mid-term due to an increase in the demand, whereas in the long term a stable price is estimated, due to the uncertainty of this fuel in the future. For coal and uranium, finally, stable prices have been foreseen for the study period between 2020 and 2050.

Based on these forecasts and the model developed in Section 3.2, the evolution of the price of electricity in the daily market has been estimated. One of the conclusions is that monthly variation of the price will be accentuated, due to the massive entrance of renewable sources (which have a clear variability throughout the year), the increase in the generation of CCGTs and the rise in the prices of both CO_2 emission rights and natural gas. Regarding the evolution of the price between 2020 and 2050, it is expected that in the mid-term it will suffer an increase, whereas in the long term it will fall below the current levels.

The economic analysis carried out in Section 4.2 for the solar PV power generation plant concludes that the project would be economically feasible, as a result of which no additional financing mechanisms would be necessary. With an approximate load factor of 22.3% calculated in Section 4.1, the plant would have an Internal Rate of Return of $IRR = 13.56\%$ and a Pay-Back of 8 years.

From the analysis of the adjustment market made in Section 4.3 it is concluded that, on the one hand, there is a correlation between the price of electricity in the daily market and the one perceived in the adjustment markets. As a result, a forecast of the price in the adjustment markets has been made, based on the forecasts of the price in the daily market. On the other, a relationship has been established between the volumes of energy traded in these markets and the amount of energy generated from renewable sources. Indeed, given the variability of these resources, which makes difficult to predict with high certainty the generation available at any time, adjustment markets acquire special relevance in the management of the electricity system.

Based on the estimations of the price in the adjustment markets, Section 4.3 concludes that the CCGT plant would also be profitable, although capacity payments would be necessary in some alternative scenarios. Assuming that all the energy generated was sold in the adjustment markets, the project would have an Internal Rate of Return of $IRR = 15.15\%$, with a Net Present Value of $NPV = 13,602,559 \text{ €}$ and a Pay-Back of 8 years.

Finally, from the alternative forecasts considered in Chapter 5, it is concluded that the forecasts of the price made in Section 3.1 are not entirely reliable. Although both forecasts show a clear convergence in the long term, the foreseen increase in the medium term by the model is excessive. As a result, the price received by the two plants could be lower than the one calculated.

In the case of solar PV plant, this price would fall from 60.61 €/MWh to 52.78 €/MWh . However, the project would still be profitable, with a return of $IRR = 12.95\%$ and a Pay-Back of 8 years. In the case of the CCGT plants, on the other hand, the price received in the market would fall from 124.6 €/MWh to 91.4 €/MWh , making the plant economically unfeasible. In this new scenario and for a 100% of sales in the adjustment market, the project would have a return of $IRR = 9.38\%$ and a negative Net Present Value of $PV = -863,470 \text{ €}$. Consequently, capacity payments would be indispensable for the viability of these power generation plants.

However, unlike solar PV plants, whose sales offers do not influence the price set in the market, marginal technologies such as CCGTs fix most of the energy they sell in the market. Therefore, it has been concluded that the average values of the price of electricity are not representative for the case of CCGTs and that, for a reliable analysis of the economic feasibility of these plants, the hourly price in the market should be studied, instead of considering monthly or annual average values.

Based on the results obtained, it is concluded that in the energy transition that Spain is going to undergo the coming decades, renewables will not imply additional costs to the electricity system, especially in the case of solar PV technology, which would be profitable as of the year 2020. Due to the massive penetration of renewables in the generator park, however, considerable backup capacity will be required in CCGTs. In order to ensure the economic feasibility of these plants, capacity payments will be essential, which will imply an additional cost in the electricity system.

7.- REFERENCES

- [1] Law 54/1997, of November 27, of the Electric Sector.
- [2] Directive 96/92/EC, of December 19, of the European Parliament and of the Council on Common Rules for the Internal Market in Electricity.
- [3] International Agreement related to the Constitution of an Iberian electricity market between the Kingdom of Spain and the Portuguese Republic, made in Santiago de Compostela in October 1, 2004.
- [4] Resolution of December 23, 2015, of the Secretary of State for Energy, by which the Operating Rules of the daily and intraday markets for the production of electric power are approved.
- [5] Cnmc.es. (2018). *Qué es la CNMC / CNMC*. [online] Available at: <https://www.cnmc.es/sobre-la-cnmc/que-es-la-cnmc#origen> [Accessed 1 Mar. 2018].
- [6] Law 24/2013, of December 26, of the Electric Sector.
- [7] Royal Decree 2019/1997, of December 26, by which the electric power production market is organized and regulated.
- [8] Omie.es. (2018). *Nuestros mercados de electricidad / OMIE*. [online] Available at: <http://www.omie.es/inicio/mercados-y-productos/mercado-electricidad/nuestros-mercados-de-electricidad> [Accessed 2 Mar. 2018].
- [9] Sociedad, E. (2018). *6.1. Formación de precios en el mercado mayorista diario de electricidad / Energía y Sociedad*. [online] Energiaysociedad.es. Available at: <http://www.energiaysociedad.es/manenergia/6-1-formacion-de-precios-en-el-mercado-mayorista-diario-de-electricidad/> [Accessed 27 Feb. 2018].
- [10] Sociedad, E. (2018). *6.5. Mecanismos de ajuste de demanda y producción / Energía y Sociedad*. [online] Energiaysociedad.es. Available at: http://www.energiaysociedad.es/manenergia/6-5-mecanismos-de-ajuste-de-demanda-y-produccion/#_ftn182 [Accessed 3 Mar. 2018].
- [11] Ree.es. (2018). *Operación del sistema eléctrico / Red Eléctrica de España*. [online] Available at: <http://www.ree.es/es/actividades/operacion-del-sistema-electrico> [Accessed 2 Mar. 2018].
- [12] Sociedad, E. (2018). *6.2. Formación de precios en los mercados mayoristas a plazo de electricidad / Energía y Sociedad*. [online] Energiaysociedad.es. Available at: http://www.energiaysociedad.es/manenergia/6-2-formacion-de-precios-en-los-mercados-mayoristas-a-plazo-de-electricidad/#_ftn171 [Accessed 4 Mar. 2018].
- [13] World Energy Outlook 2017, IEA.
- [14] 2018 BP World Energy Outlook.
- [15] World Energy Outlook 2015, IEA.

- [16] Ec.europa.eu. (2018). *Database - Eurostat*. [online] Available at: <http://ec.europa.eu/eurostat/data/database> [Accessed 10 Apr. 2018].
- [17] EnergyNews.es. (2018). *El consumo de energía primaria en España baja un 12% entre 2006 y 2012 por falta de demanda y gracias a las renovables*. [online] Available at: <https://www.energynews.es/el-consumo-de-energia-primaria-en-espana-baja-un-12-entre-2006-y-2012-por-falta-de-demanda-y-gracias-a-las-renovables/> [Accessed 15 Apr. 2018].
- [18] PriceWaterhouseCoopers (2018). *El modelo eléctrico español en 2030. Escenarios y alternativas*. Crecimiento inteligente.
- [19] Comisión Nacional de los Mercados y la Competencia (2017). *Informe de supervisión del mercado mayorista y aprovisionamiento de gas*. [online] Available at: <http://www.cnmc.com> [Accessed 18 Apr. 2018].
- [20] Ree.es. (2018). *Red Eléctrica de España | Series estadísticas nacionales*. [online] Available at: <http://www.ree.es/es/estadisticas-del-sistema-electrico-espanol/series-estadisticas/series-estadisticas-nacionales> [Accessed 10 Apr. 2018].
- [21] Ree.es. (2018). *Red Eléctrica de España | Refuerzo de las interconexiones*. [online] Available at: <http://www.ree.es/es/red21/refuerzo-de-las-interconexiones> [Accessed 17 Apr. 2018].
- [22] EIMundo.es. (2018). *El mercado apunta a una subida de la luz del 2,5% en 2018 tras el fuerte incremento de este año*. [online] ELMUNDO. Available at: <http://www.elmundo.es/economia/2017/12/28/5a43e8c446163fd6168b459e.html> [Accessed 19 Apr. 2018].
- [23] Red Eléctrica de España (2017). *Informe del Sector Eléctrico Español 2016*. [online] Available at: <http://www.ree.es> [Accessed 9 Apr. 2018].
- [24] Informe de precios 2017. (2018). [online] OMIE. Available at: <http://omie.es> [Accessed 18 Apr. 2018].
- [25] Deloitte (2016). *Un modelo energético sostenible para España en 2050. Recomendaciones de política energética para la transición*.
- [26] GDF Suez Energía España (2014). *La competitividad de los ciclos combinados en el mercado eléctrico español*. Cuadernos de Energía.
- [27] Minetad.gob.es. (2018). *Estadísticas eléctricas anuales - Estadísticas y Balances Energéticos - Energía - Mº de Energía, Turismo y Agenda Digital*. [online] Available at: <http://www.minetad.gob.es/energia/balances/Publicaciones/ElectricasAnuales/Paginas/ElectricasAnuales.aspx> [Accessed 17 Apr. 2018].
- [28] MERTENS, K. (2018). *PHOTOVOLTAICS*. [S.I.]: WILEY-BLACKWELL.
- [29] Anon, (2018). [online] Available at: <https://www.newport.com/t/introduction-to-solar-radiation> [Accessed 24 Apr. 2018].
- [30] Department for Business, Energy and Industrial Strategy (November 2016). *Electricity Generation Costs*.

- [31] Sociedad, E. (2018). *Cada vez más países europeos se comprometen con el cierre de las centrales de carbón* | *Energía y Sociedad*. [online] Energiaysociedad.es. Available at: <http://www.energiaysociedad.es/boletin/cada-vez-mas-paises-europeos-se-comprometen-con-el-cierre-de-las-centrales-de-carbon/> [Accessed 10 May 2018].
- [32] Landberg, R. and Eckhouse, B. (2018). *Solar Energy*. [online] Bloomberg.com. Available at: <https://www.bloomberg.com/quicktake/solar-energy> [Accessed 9 May 2018].
- [33] MIBGAS (2018). Informe anual del mercado organizado de gas, 2017.
- [34] Meteorología, A. (2018). Agencia Estatal de Meteorología - AEMET. Gobierno de España. [online] Aemet.es. Available at: http://www.aemet.es/es/lineas_de_interes/datos_y_estadistica [Accessed 28 Apr. 2018].
- [35] Adrase.com. (2018). ADRASE - Acceso a datos de radiación solar de España - Inicio. [online] Available at: <http://www.adrase.com/> [Accessed 27 Apr. 2018].
- [36] Indexmundi.com. (2018). *Commodity Prices - Price Charts, Data, and News - IndexMundi*. [online] Available at: <https://www.indexmundi.com/commodities/> [Accessed 18 May 2018].
- [37] Cnmc.es. (2018). *Informes supervisión mercado mayorista* | *CNMC*. [online] Available at: https://www.cnmc.es/listado/sucesos_energia_mercado_gas_informes_supervision_mercado_mayorista/block/250 [Accessed 16 May 2018].
- [38] Sendeco2.com. (2018). *Precios CO2* - *Sendeco2*. [online] Available at: <https://www.sendeco2.com/es/precios-co2> [Accessed 15 May 2018].
- [39] Économie et écologie: énergies, technologies et société. (2018). *El rendimiento de una central nuclear - La electricidad y la energía nuclear*. [online] Available at: <https://es.econologie.com/Rendimiento-central-nuclear/> [Accessed 20 May 2018].
- [40] Ministerio de Energía, Turismo y Agenda Digital (2017). *La Energía en España 2016*.
- [41] Calventus, Y. *Tecnología Energética y Medio Ambiente*, vol. 1.
- [42] Climate Action - European Commission. (2018). *EU Emissions Trading System (EU ETS)* - *Climate Action - European Commission*. [online] Available at: <https://ec.europa.eu/clima/policies/ets/> [Accessed 14 May 2018].
- [43] S.L., 2. (2018). *El precio al CO2 y la UE*. [online] Expansion. Available at: <http://www.expansion.com/blogs/cambioclimatico/2017/12/07/el-precio-al-co2-y-la-ue.html> [Accessed 17 May 2018].
- [44] Iberdrola. (2018). *El precio del CO2 debe incentivar el desarrollo de energías limpias*. [online] Available at: <https://www.iberdrola.com/conocenos/perfil-compania/regulacion-nuestra-vision/precio-co2> [Accessed 15 May 2018].
- [45] Ecoavant. (2018). *Precios altos para el carbono dispararía la reducción de CO2*. [online] Available at: <http://www.ecoavant.com/es/notices/2018/01/precios-altos-para-el-carbono-dispararia-la-reduccion-de-co2-3666.php> [Accessed 19 May 2018].

- [46] Primas, M. (2018). *Precio petróleo Brent 2017*. [online] datosmacro.com. Available at: <https://www.datosmacro.com/materias-primas/brent?anio=2017> [Accessed 11 May 2018].
- [47] Ofgem.gov.uk. (2018). *Gas prices: Day-ahead contracts – monthly average (GB)*. [online] Available at: <https://www.ofgem.gov.uk/data-portal/gas-prices-day-ahead-contracts-monthly-average-gb> [Accessed 17 May 2018].
- [48] GasINDUSTRIAL Asociación para un Gas Industrial Competitivo. (2018). *¿Por qué lo llamamos petróleo cuando queremos decir gas?*. [online] Available at: <https://www.gasindustrial.es/2016/07/19/por-qu%C3%A9-lo-llamamos-petr%C3%B3leo-cuando-queremos-decir-gas/> [Accessed 21 May 2018].
- [49] CaixaBank Research. (2018). *El desacoplamiento entre los precios del gas y del petróleo*. [online] Available at: <http://www.caixabankresearch.com/1501im-f2-es> [Accessed 17 May 2018].
- [50] Anon, (2018). [online] Available at: <https://elperiodicodelaenergia.com/radiografia-del-carbon-en-espana-aumenta-la-produccion-un-60-y-crece-el-empleo-un-7-en-2017/> [Accessed 18 May 2018].
- [51] Primas, M. (2018). *Uranio, NUEXCO, Precio restringido, precio por tonelada métrica 2017*. [online] datosmacro.com. Available at: <https://www.datosmacro.com/materias-primas/uranio> [Accessed 15 May 2018].
- [52] Deambi, S. (2016). *Photovoltaic System Design*. Milton, UNKNOWN: CRC Press.
- [53] Solargis.com. (2018). *Bankable solar data for better decisions*. [online] Available at: <https://solargis.com/> [Accessed 25 Apr. 2018].
- [54] Ree.es. (2018). *Mapas de la red | Red Eléctrica de España*. [online] Available at: <http://www.ree.es/es/actividades/gestor-de-la-red-y-transportista/mapas-de-la-red> [Accessed 27 Apr. 2018].
- [55] Google.es. (2018). [online] Available at: https://www.google.es/maps?q=maps&um=1&ie=UTF-8&sa=X&ved=0ahUKEwiA2fj0j-LaAhXEaVAKHQOcBskQ_AUICigB [Accessed 28 Apr. 2018].
- [56] 2018, L. and Insa, +. (2018). *Los mejores fabricantes de paneles solares 2018*. [online] Monsolar. Available at: <https://www.monsolar.com/blog/mejores-fabricantes-paneles-solares-2018/> [Accessed 28 Apr. 2018].
- [57] Jinkosolar.com. (2018). *Jinko Solar | Your Best Supplier of Modules, Cells & Wafers*. [online] Available at: https://www.jinkosolar.com/product_56.html?lan=sp [Accessed 27 Apr. 2018].
- [58] Law 82/1980, of December 30, on energy conservation.
- [59] National Energy Plan 1991-2000, of September 13, 1991.
- [60] Plan for the Promotion of Renewable Energies, December 1999.
- [61] Royal Decree 2366/1994, of December 9, on the generation of electric power by hydraulic, cogeneration and other facilities supplied by renewable energy sources.

[62] Royal Decree 2181/1998, of December 23, on the generation of electric power by facilities supplied by renewable energy sources, waste and cogeneration.

[63] Kyoto Protocol from the United Nations Framework Convention on Climate Change, 1998.

[64] Anon, (2018). [online] Available at: <http://www.mapama.gob.es/es/cambio-climatico/temas/el-proceso-internacional-de-lucha-contra-el-cambio-climatico/naciones-unidas/protocolo-kioto.aspx> [Accessed 14 Mar. 2018].

[65] Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market.

[66] Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC.

[67] Minetad.gob.es. (2018). *Plan de Energías Renovables 2005-2010 - Energía y desarrollo sostenible - Energía - Mº de Energía, Turismo y Agenda Digital*. [online] Available at: <http://www.minetad.gob.es/energia/desarrollo/EnergiaRenovable/Plan/Paginas/planRenovables.aspx> [Accessed 14 Mar. 2018].

[68] Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

[69] Summary of the Renewable Energy Plan 2001-2020.

[70] The economic-financial situation of electricity activity in Spain, Spanish Association of the Electric Industry UNESA.

[71] Royal Decree 1544/2011, of October 31, which establishes access tolls for transport and distribution network that must be fulfilled by electric power producers.

[72] Sociedad, E. (2018). 7.2. *El déficit tarifario: qué es, consecuencias y solución | Energía y Sociedad*. [online] [Energiaysociedad.es](http://www.energiaysociedad.es). Available at: <http://www.energiaysociedad.es/manenergia/7-2-el-deficit-tarifario-que-es-consecuencias-y-solucion/> [Accessed 15 Mar. 2018].

[73] Law 17/2007, of July 4, amending Law 54/1997, of November 27, on the electricity sector, to adapt it to the provisions of Directive 2003/54/EC, of the European Parliament and of the Council of 26 June 2003 on common rules for the internal market in electricity.

[74] Royal Decree 1432/2002, of December 27, which establishes the methodology for the approval or modification of the average or reference electricity tariff and modifies some articles of Royal Decree 2017/1997m of December 26, whereby the procedure of liquidation of the transport, distribution and marketing costs as a tariff, of the permanent costs of the system and of the costs of diversification and security of supply is organized and regulated.

[75] Royal Decree 1634/2006, of December 29, which establishes the electricity tariff as of January 1, 2007.

[76] Royal Decree 841/2002, of August 2, which regulates the production of electric power on the special regime, its incentive to participate in the production market, certain information obligations of its production forecasts and the acquisition by the marketers of their produced electric power.

[77] Royal Decree 436/2004, of March 12, which establishes the methodology for the updating and systematization of the legal and economic regime of the activity of production of electric power under the special regime.

[78] Sociedad, E. (2018). *3.5. Regulación española de las energías renovables | Energía y Sociedad*. [online] Energiaysociedad.es. Available at: <http://www.energiaysociedad.es/manenergia/3-5-regulacion-espanola-de-las-energias-renovables/> [Accessed 14 Mar. 2018].

[79] Royal Decree 661/2007, of May 25, which regulates the activity of production of electric power under the special regime.

[80] Royal Decree-Law 6/2009, of April 30, by which certain measures are adopted in the energy sector and the social bonus is approved.

[81] Royal Decree-Law 1/2012, of January 27, which proceeds to the elimination of the pre-allocation of remuneration procedures and the elimination of economic incentives for new facilities for the production of electricity from cogeneration, sources of renewable energy and waste.

[82] Royal Decree-Law 2/2013, of 1 February, on urgent measures in the electricity system and in the financial sector.

[83] Royal Decree-Law 9/2013, of July 12, by which urgent measures are adopted to guarantee the financial stability of the electric system.

[84] Royal Decree 413/2014, of June 6, which regulates the activity of production of electric power from renewable energy sources, cogeneration and waste.

[85] Minetad.gob.es. (2018). *Estadísticas eléctricas anuales - Estadísticas y Balances Energéticos - Energía - M^º de Energía, Turismo y Agenda Digital*. [online] Available at: <http://www.minetad.gob.es/energia/balances/Publicaciones/ElectricasAnuales/Paginas/Electri casAnuales.aspx> [Accessed 15 Mar. 2018].

[86] Acción por el Clima - European Commission. (2018). *Marco sobre clima y energía para 2030 - Acción por el Clima - European Commission*. [online] Available at: https://ec.europa.eu/clima/policies/strategies/2030_es [Accessed 15 Mar. 2018].

[87] Acción por el Clima - European Commission. (2018). *Una economía baja en carbono para 2050 - Acción por el Clima - European Commission*. [online] Available at: https://ec.europa.eu/clima/policies/strategies/2050_es [Accessed 15 Mar. 2018].

[88] DÍAS, C. (2018). *Tribuna | Déficit de tarifa o sobre coste de capacidad*. [online] Cinco Días. Available at: https://cincodias.elpais.com/cincodias/2016/12/16/empresas/1481902389_675893.html [Accessed 15 Mar. 2018].

[89] EnergyNews.es. (2018). *Un informe del IEEFA dice que la estructura de los mecanismos de capacidad es obsoleta*. [online] Available at: <https://www.energynews.es/informe-del-ieefa-dice-la-estructura-los-mecanismos-capacidad-espana-obsoleta/> [Accessed 15 Mar. 2018].

[90] Sociedad, E. (2018). 3.4. *Mecanismos de apoyo a las energías renovables* | *Energía y Sociedad*. [online] Energiaysociedad.es. Available at: <http://www.energiaysociedad.es/manenergia/3-4-mecanismos-de-apoyo-a-las-energias-renovables/> [Accessed 16 Mar. 2018].

[91] García-Álvarez, M., Cabeza-García, L. and Soares, I. (2017). Analysis of the promotion of onshore wind energy in the EU: Feed-in tariff or renewable portfolio standard?. *Renewable Energy*, 111, pp.256-264.

[92] Kwon, T. (2015). Rent and rent-seeking in renewable energy support policies: Feed-in tariff vs. renewable portfolio standard. *Renewable and Sustainable Energy Reviews*, 44, pp.676-681.

[93] Paris Agreement from the United Nations Framework Convention on Climate Change, 2015.

8.- APPENDICES

8.1.- Legislative development regarding renewable generation

8.1.1.- *Precedents*

The **Law 82/1980** constituted the first regulation regarding renewable energies in Spain, as a result of the rise of the oil price due to the crisis of 1973. It established the rules and basic principles in order to promote the adoption of renewable energy sources by means of a benefit regime, thus reducing the consumption of fossil fuels and, in general, the external energy dependence [58].

In the beginning of the next decade the **National Energy Plan 1991-2000** was approved, in order to deal with the scarce endowment of country's own energy resources and the necessity of improving the energy efficiency. Among the different action programmes, it was considered to increase the electricity generation by renewable sources to 4179 GWh/year [59], achieving in 1998 a contribution of 6,3% of renewable energies in terms of primary energy consumption [60].

The **Royal Decree 2366/1994** developed the regulation initiated by the Law 82/1980, defining for the first time a special regime for these technologies, as well as establishing an economic regime which could provide them with an adequate profitability, without the consequence of an increase in the regulated tariffs [61].

8.1.2.- *The special regime*

With the entry into force of the **Law 54/1997** and the subsequent liberalization of the electricity market, the generation activity in special regime was distinguished from the ordinary one, establishing the economic framework of retribution for each of them [1].

According to this law, the generation activity in special regime includes the generation of electricity in facilities with a power equal or smaller than 50 MW that use renewable energy or non-renewable waste as primary energy, as well as those which use high-performance cogeneration [1].

Unlike the production units under the ordinary regime, which are obliged to make economic offers to the Market Operator for each programming period, those under the special regime are exempt from this obligation, having however the right to transfer to the system their production and perceiving for that the final mean hourly price of the market. Moreover, the said generators have the option to access the offers system in the wholesale market or to formalize bilateral physical contracts, in both cases for annual periods [62].

In any of these cases, the activities carried out under the special regime receive an additional remuneration premium, composed of a term per unit of installed power that covers the investment costs of a typical facility that can not be recovered by the sale of energy, and a term to the operation that covers the difference between the operating costs and the income generated as a result of participating in the market. This retribution regime is intended to cover the costs without which the facilities under the special regime can compete in the market on equal terms with the rest of technologies, habilitating as well a reasonable profitability [62].

The **Royal Decree 2818/1998**, likewise, with the objective of providing the necessary incentives for technologies with an insufficient level of competition, established the right to the said premiums for facilities that use non-consumable and non-hydraulic renewable energy, biomass, biofuels or agricultural waste as primary energy, despite having an installed power exceeding 50 MW [62].

8.1.3.- Promotion of renewable energies

In the United Nations Framework Convention on Climate Change of 1997, the **Kyoto Protocol** was approved, where legally binding commitments were established in order to reduce or limit emissions of greenhouse effect. The said Protocol, which came into force in February 2005, established as a goal for industrialized countries to reduce emissions by at least 5% below 1990 levels, for the period between 2008 and 2012. The European Union assumed a reduction of 8%, making a modular distribution among the Member States. Spain, for its part, assumed the responsibility of not exceeding the 15% of the base year emissions [63] [64].

With the objective of promoting an increase in the contribution of renewable energy sources to the generation of electricity, the **Directive 2001/77/EC** established as a global guidance objective for 2010 that 12% of primary energy consumption should come from renewable energy sources, as well as 22,1% of electricity generated from the said sources [65]. Equally, as a framework to promote and monitor the compliance with the objectives set by the Kyoto Protocol, the European Union launched in January 2005 a Community market for greenhouse gas emission rights, which made possible to allocate a cost to CO₂ emissions and thus create an economic incentive to reduce emissions [66].

At the national level, the **Plan for the Promotion of Renewable Energies 1999** developed a strategy so that the growth of each renewable technology could cover, as a whole, more than 12% of primary energy consumption in 2010 [60]. Subsequently, with the purpose of reinforcing the priority objectives of the energy policy (security of the electricity supply and respect for the environment), the **Renewable Energy Plan 2005-2010** drawn up, which replaced the previous one due to its insufficient results. The latter set, for 2010, the objective that 12,1% of primary energy consumption was supplied by renewable energies, as well as a share in electricity generation of 30,3% of gross electricity consumption. Regarding different technologies, 20.155 MW of installed wind power, 500 MW of thermoelectric solar and 400 MW of photovoltaic solar were forecasts, among others [67].

In the last decade, the **Directive 2009/28/EC**, as part of the European Energy and Climate Change Package, and repealing the Directive 2001/77/EC, set as general objectives to achieve a 20% share of energy from renewable sources in the primary energy consumption of the European Union, and a 10% share of energy from renewable sources in fuel consumption for transportation by 2020. The said directive, unlike the previous one, established compulsory and specific national objectives for each Member State, determining intermediate indicative objectives for their compliance. In the case of Spain, the established objective was coincident with the European average, that is, 20% [68], for whose attainment **Renewable Energy Plan 2011-2020** was approved, establishing objectives according to the aforementioned directive [69].

8.1.4.- The problem of the tariff deficit

The tariff deficit is the result of the difference between the revenues collected for the remuneration of regulated activities and the costs that have to be covered with charge to them [70], which are formed, according to the **Law 54/1997**, by the costs associated with distribution and transport activities, those due to the additional remuneration for facilities under the special regime, as well as other costs paid under the system. The said costs are financed with access tolls for transport and distribution networks, satisfied by both consumers and generators [58] [71].

With the objective of adjusting the terminology to the one used in European directives, the **Law 24/2013** introduced a distinction between “network access tolls”, responsible for covering the costs of transport and distribution networks, and “charges”, responsible for financing the rest of regulated services of the system, among others the specific retributive regime for generation activities from renewable energy sources, high efficiency cogeneration and waste [62].

In the first stage of the liberalization of the electricity market, the tariff deficit was a result of the difficulty of equalizing the cost of energy considered in the integral tariffs approved by the Government, with the prices resulting from the already liberalized electricity market [72]. With the approval of the **Law 17/2007**, nevertheless, from 2009 the supply happened to be exercised by the marketers in free competition, so that the said deficit was due to the imbalance between the established access tolls and the costs of activities retributed in a regulated way [73].

It should be noted that the difference between the forecasted costs and the ones subsequently generated can be circumstantial, due to an error in the forecast of some variables, such as the electricity price in the wholesale market, the availability of renewable sources or the final electricity demand. In the case these forecasts were unbiased, the said deficit would be counteracted by means of future surpluses, so that the accumulated deficit would be zero [70] [1].

In Spain, however, the successive tolls approved by the Government since 2000 generated reiteratively tariff deficits, resulting in a structural deficit whose main cause no longer consisted in forecast errors, but in deliberate political decisions made by the Administration. This imbalance between regulated tariffs and the real costs was mainly articulated through the **Royal Decree 1432/2002**, which established a maximum growth rate of 2% for regulated tariffs, without taking into account the evolution of costs, subjected to the dynamics of their respected markets [74]. Far from solving the problem, the **Royal Decree 1634/2006** assumed an *ex ante* deficit in the setting of tariffs for the year 2007, recognizing explicitly a tariff insufficiency [75].

Thus, the regulatory authorities in Spain approved, in order to control inflation or avoid the rise in the price of electricity that would reduce the competitiveness of certain industries, regulated tariffs below the explicit costs of energy, resulting, year after year, in insufficient revenues [1]. The financing of this deficit was assumed, from the beginning, by the five largest Spanish electricity companies. As of 2003, however, an entitlement process was initiated by means of which these ones were able to transmit the accumulated debt to third parties, converting the collection rights into a negotiable instrument in exchange for an interest [70].

On the other hand, with the objective of reducing the costs associated with the regulated activities, a stage of modification of the special regime was started that could allow, nevertheless, the attainment of the objectives established in matter of renewable energies. Thus, the **Royal Decree 841/2002** established the obligation, for installations with a capacity exceeding 50 MW under the special regime, to submit bids to the Market Operator [76].

The **Royal Decree 436/2004**, whereby the Royal Decree 2818/1998 is repealed and with the objective of establishing a durable and stable economic regime for the facilities under the special regime, determined two optional retribution mechanisms for it [77]:

- 1) Sell the electricity to the distribution company at a Feed-in tariff (FIT), unique for all programming periods, as a percentage of the average electricity tariff.
- 2) Sell the electricity freely in the market, through the bidding system managed by the Market Operator, the bilateral or term-contracting system or a combination of all of them, perceiving the market price plus an incentive to participate in it, as well as a premium defined generically as a percentage of the average electricity tariff.

The **Royal Decree-law 7/2006**, for its part, modified the previous Royal Decree, separating the calculation of the premiums for the special regime from the average electricity tariff [78]. Subsequently, the Royal Decree 436/2004 was substituted by the **Royal Decree 661/2007**, in which a similar remuneration system was maintained, establishing however lower and higher limits for the sum of the hourly market price, plus a reference premium, so that the premium to be received in each hour could be bounded according to these values. The objective of this new system was to remove irrationalities in the retribution of different technologies, protecting generator when the income derived from the market price was excessively low, and suppressing the premium when the market price covered their costs [79].

As of the year 2008, the tariff deficit increased significantly, having the premiums for the special regime an increasingly incidence. Thus, in order to guarantee the sustainability of the system in relation to the retributive system of the special regime, the **Royal Decree-law 6/2009** established the mechanism of registration of pre-assignment of remuneration for the facilities under the special regime, by means of which it was possible to determine the projects that fulfil the required conditions [80].

Due to the complex economic and financial situation of the country, in January 2012 the **Royal Decree-law 1/2012** was approved, by which the incentives for the construction of special regime facilities were suppressed, as well as the suspension of their remuneration pre-assignment procedure [81]. In the same vein, and in order to avoid an overpayment of facilities under the special regime, the **Royal Decree-law 2/2013** eliminated the reception of the premiums, sustaining the said regime either in the option of Feed-in tariffs or alternatively in the sale of electricity in the market, without any premium [82].

Finally, due to the unsustainability of the deficit of the electric sector, whose accumulated debt amounted to 26.062,51 million euros in mid-2013, as well as considering that 40% of the costs of access to networks, approximately, corresponded to the retribution of the special regime, the **Royal Decree-law 9/2013** suppressed the latter, thus abandoning the incentive model established by the **Law 54/1997** [83].

8.1.5.- Current situation

The new legal and economic regime, established by the **Law 24/2013**, abandoned the differentiated concepts of ordinary and special regime, establishing a unified regulation. As a result, the remuneration regime for renewable energies is currently based on the necessary participation in the market of these facilities, with their retribution being as follows [6]:

- 1) The energy negotiated within the daily and intraday markets, which is paid on the basis of the price resulting from the balance between supply and demand of electric power offered in it.
- 2) The system adjustment services, required for guaranteeing an adequate supply to the consumer.

Additionally, it was established the possibility of setting a specific remuneration regime to encourage generation from renewable energy sources, high efficiency cogeneration and waste, in case of being an obligation to comply with energy objectives derived from Directives or other rules established by the European Union [6]. The said regime was established the next year with the approval of the **Royal Decree 413/2014**, giving an additional retribution to the aforementioned facilities, consisting of a term per unit of installed power (€/MW) to cover the investment costs that can not be recovered from the sale of energy in the market, and a term to the operation (€/MWh) to cover the difference between operating costs and income from the participation in the market [84].

The granting of the said remuneration regime is established through competitive concurrency procedures, and for its calculation are considered, for a typical installation, throughout its regulatory useful life and in reference to the activity carried out by an efficient and well-managed company [6]:

- 1) The standard income from the sale of the energy valued at the price of the market.
- 2) The standard operating costs.
- 3) The standard value of the initial investment.

Regarding the current situation of renewable energies in Spain, according to the Ministry of Energy, Tourism and Digital Agenda, renewable energies accounted for 16,9% of gross final energy consumption in 2015, so new auctions of electric power adjudication will be necessary in order to reach the 20% set by the European Union for the year 2020 [85].

Furthermore, in the 2015 United Nations Climate Change Conference (COP21) the **Paris Agreement** was signed by 196 countries. The expected result of the agreement is to hold the increase in the global average temperature to well below 2°C above pre-industrial levels, as well as to make efforts to limit this increase to 1.5°C [93].

Along these lines, taking into account the objectives of the European framework on climate and energy for 2030, as well as the road map for a low carbon economy by 2050 [87], it is deduced that electric power generation from renewable energy sources will continue growing over the next years.

Lastly, although the deficit problem has been reversed with the current regulations, accumulating between the years 2014 and 2016 a surplus of 910 million of euros, it should be

noted that capacity payments regulated by the Government have played an important role in it [88]. Notwithstanding, the said mechanisms could be modified and reduced due to their controversy, so the problem of the tariff deficit could recur in the coming years, having a negative effect on the generation technologies from renewable energy sources [89].

8.2.- Financing methods

8.2.1.- Participation in the spot market

8.2.1.1.- Offers retribution

The offers presented by generators in the Spot market represent the energy quantity that are willing to sell from minimum prices, which vary depending on the technology. These prices reflect, on the one hand, the physical restrictions to which facilities are subject in terms of the amount of energy possible to offer. In any case, the production units are obliged to conduct economic offers of all their available capacity to the Market Operator for each programming period [6].

On the other, reflect the opportunity cost that implies generating electricity, in which two concepts are considered: the costs which would be avoided in the case of not generating and the income given up due to generating. The said cost is the one which determines the price offered in the market, which is different, in general, to the variable cost associated with the generation activity. The fact that offers are built from their opportunity costs is, in effect, what makes the market an efficient resource allocation mechanism [9].

It should be pointed out that, since it is not possible to avoid incurring them, fixed costs are not part of the opportunity cost of generating electricity, so these ones are not included in the offers carried out in the market. The recovery of fixed costs occurs through the market margin, that is, the difference between the price received in the market and the variable costs incurred in the generation of the sold energy [9].

Nevertheless, the said margin results insufficient for the technologies that set the price in the market, given that, being equal to the price offered by these technologies and, therefore, equal to their opportunity costs, the margin whereby the fixed costs should be recovered is zero. If fixed costs were only recovered through the said margin, which is known as an Energy-Only Market, investment would be discouraged, leading to a capacity deficit for which electricity supply would not be insured. In this case, due to the low availability of the energy, prices received in the market would be higher than the opportunity costs of peak technologies, allowing the recovering of their fixed costs. The market margin, hence, allows for recovering the costs only in the case that there is a capacity deficit, which does not result acceptable, given the high prices and lack of security of supply that leads to [9].

In order to reduce the fixed costs that the plants have to recover by the market margin, capacity payments are carried out, which are determined based on the fixed costs of a peak plant. By means of the capacity mechanisms investment incentive is achieved, avoiding the capacity deficit aforementioned, so that the market margin and capacity payments are enough to recover the fixed costs [9].

8.2.1.2.- Integration of renewable energies

Generation technologies from renewable energy sources are characterized, in general, by high investment costs, given their lack of technological maturity compared to conventional technologies, as well as by small variable costs, in the case of technologies that do not use any type of fuel (solar, wind, etc.). Given the small variable costs of these technologies, which are, in their case, practically equal to their opportunity costs, renewable energies have an important effect on the market price, since they shift the supply curve and cause the market price to be fixed by cheaper technologies [9].

Besides that, given the unpredictability of renewable technologies, their pattern of operation does not correlate with market prices, not being able to choose the optimal programming period by which maximize their revenues. Therefore, the price they receive from the market is exclusive function of the relationship between their production profile and the market price profile, receiving generally a lower market price than the average [9].

This fact, added to their higher investment costs compared to conventional technologies, hinders their competitiveness in the market, requiring additional support to meet their costs [90].

8.2.2.- Support mechanisms

Support mechanisms to encourage deployment of renewable energies may be divided into two fundamental schemes: price-driven and quantity-driven [91]. The first one is carried out through a fiscal or financial aid per kW of installed capacity, or through the total or partial fixing of tariffs to be received for each kWh generated from renewable energies. The second one, through the legal establishment of a level of power or generation to be achieved, so that the price of the said energy is fixed in the market [90]. The most widespread support systems in relation to these mechanisms are, respectively, Feed-in tariffs (FIT) and Green Certificates (GC) [91].

8.2.2.1.- Feed-in tariffs

Feed-in tariff system is the one which prevails currently in a majority way in the European Union, being its implementation in countries such as Germany or Spain (eliminated in 2013, as mentioned above) examples of success in terms of promoting generation from renewable technologies [90] [92]. These systems are characterized by fixing administratively prices, whose amounts vary according to the characteristics of the different technologies, especially their maturity. The collection of the said price is determined for a period of time, which may cover the useful life of the facility [90].

Among its diverse forms, there are constant FITs or FITs which evolve annually in proportion to the inflation index, as well as FITs with the same level during the useful life of the facility or with two levels, a high one during the first years and a lower afterwards. Likewise, partial FITs are also common, according to which generators receive the price of the wholesale market plus a premium fixed by the government [91].

In any case, the main advantages of FITs consist, on the one hand, of the stability in the retribution, which reduces drastically the investment risk, guaranteeing a reasonable profitability. On the other, provides a differential support for each technology, adapting to their needs according to their maturity. In regard to their drawbacks, FITs can have a negative effect

in the competitiveness of the said technologies, since they disincentivise their cost reduction. Moreover, given that the regulation is based on a limited information about the costs of these technologies (information asymmetry), generators can have surplus (windfall) profits that increase the costs of the incentives of renewable energies [92].

8.2.2.2.- Green Certificates

This system consists of imposing legally to electricity consumers, suppliers or generators, according to the case, a percentage or quota of their supply or generation coming from renewable energies. The fulfilment of this quota is verified by the delivery of Green Certificates to the authorities, which are equivalent to the quota in terms of MWh coming from renewable energies [90].

Regulatory authorities grant GCs generators based on their production from renewable energy sources. These, for their part, sell the said certificates to suppliers that are obliged to fulfil a certain quota, either directly or in a market of CVs that is launched in parallel to the electricity market. Unfulfillment of this quota by the suppliers supposes a penalty, which can be economic or of a different nature, such as the withdrawal of license, for instance [90].

The main advantage of Green Certificates consists of their market-orientation, which promote competition between generators, reducing thus the costs of the support system. Notwithstanding, given that the amount of the penalty marks a theoretical maximum price to the certificates, the price does not fully correspond to the market conditions fixed by supply and demand [90].

Regarding the disadvantages, the granting of CVs is a technologically neutral system, so that they promote solely the deployment of the most competitive technologies, which is detrimental to those with a lower degree of maturity. In order to solve this problem, some countries have introduced technological differentiation with a banding system, by means of which a different number of CVs are assigned for each kWh generated depending on the technology [90].

8.2.2.3.- Other type of supports

There are other ways to support the generation from renewable energy sources, either through investment subsidies, tax incentives or power auctions. The latter consist of the allocation by a generator, of a certain power to be covered, reaching an agreement of a long-term contract for electricity sale. Auctions can turn out to be efficient mechanisms for supporting renewable energies, since they allow competition between generators as they grant the contract to the cheapest offer. Furthermore, they allow to limit the installed capacity, which facilitates the control to the System Operator, and offer a stable long-term remuneration, reducing uncertainty and risk associated with investment projects.

Lastly, there exist indirect mechanisms that have an impact on the promotion of renewable energies, such as ecotaxes for non-renewable generation or CO₂ emission rights, among others [90].